August 8, 2013

Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Attention: Mr. Bruce McLennan
Board Chairman

Dear Sir:

RE: Yukon Electrical 2013-2015 General Rate Application
Information Responses

In accordance with Board Order 2013-06, Yukon Electrical has attached 348 Information Responses. Yukon Electrical will file the complete package of Information Responses, including those currently outstanding, by August 29, 2013.

If you have any questions on the above, please contact me at (780) 733-2489.

Yours truly,

Original Signed by

James Grattan, CA
Director, Regulatory

CW-YECL-1

Reference: Sales and Revenue, YECL Application, Page 2-4

In its Application, YECL states:

> The forecast process involves the review of historic sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. The information is obtained through Yukon Electrical's work in the community, as well as consultation with the City of Whitehorse, Yukon Government, and various local agencies and developers.

The City requires an understanding of the communications and consultations used in developing forecast sales.

Request:

(a) Please provide copies of all communications with "the City of Whitehorse, Yukon Government, and various local agencies and developers" related to sales forecasts. If there are no written communications, please provide summaries of verbal communications.

Response:

(a) As noted in the Application, Yukon Electrical's sales, and associated capital forecast, takes into account consultations with City of Whitehorse and Yukon Government officials as well as local developers that allow Yukon Electrical to identify customer additions. The Company's involvement with the local Chamber of Commerce also serves to identify projects that will result in new distribution extensions and or new customers. While this process has been in place for many years, it has taken on added importance of late as customers have recognized the importance of communicating their plans to Yukon Electrical given the long lead times required to obtain key pieces of electrical infrastructure. The information received as part of these consultations allows Yukon Electrical to identify what, if any, additional resources may be required to meet customer's capital needs and reflect new customers and load in its sales forecast.

The key information obtained from the City of Whitehorse and the Yukon Territorial Government (YTG) was their respective capital plans. The City of Whitehorse's plan provides information related to development in the Whitehorse area while the YTG plan provides government development plans for projects throughout the Yukon. As noted above, the capital plan information allows Yukon Electrical to identify what, if any, additional resources may be required to meet customers capital needs and reflect new customers and load in its sales forecast.

Regarding communication with the YTG and other agencies, Yukon Electrical relied on published materials from the Government and information through media (TV, newspapers). For the published materials, please refer to YUB-YECL-56 and the Canada Mortgage and Housing Corporation website (http://www.cmhc-schl.gc.ca/odpub/esub/65446/65446_2012_A01.pdf?lang=en), Northern Housing Report, released in 2012.

CW-YECL-2

Reference: Sales and Revenue, Application, Page 2-5

In its Application, YECL states:

> Over the past 2-3 years, housing developments in Whitehorse have been using electricity for space heating, which has resulted in an increase in residential average UPC. As a result, in forecasting Whitehorse UPC in 2013, Yukon Electrical used the 2012 weather-normalized UPC, which already reflects the consumption increases due to space heating, as a base and raising it by the most recent three-year average growth in weather-normalized UPC. The increase in UPC relating to electric space heating, however, is not expected to be extended beyond 2013, as it is expected to be offset by a reduction in consumption due to the demand side management program. 17 Attachments 1 to 21 show the historical data as well as the regression results.

It appears that there has been a shift in the use of electricity, with newer houses using electricity for space heating. Based on the shift, there may well be different usage patterns for the different uses. The City requires information to assess the forecast of sales, based for the various uses.

Request:

(a) Please provide a schedule similar to Schedule 2.1 containing 2008, 2009, 2010, 2011, and 2012 actual, and 2013-2015 forecast actual and normalized sales, average customers and actual and normalized average use per customer for the City of Whitehorse, separating customers that use electricity for space heating and those that do not use electricity for space heating.

(b) Please provide the response to (a) above in Excel format

(c) Please provide Attachments 1 to 21 in Excel format with formulae intact.

Response:

(a - b) Please refer to CW-YECL-2(a) Attachment 1 for the City of Whitehorse actual and forecast data in a format similar to Schedule 2.1. As noted on pages 2-5 and 2-6 of the Application, Whitehorse residential and commercial UPC and energy forecasts for the test period are all weather-normalized. A non-weather-normalized forecast is not available. In addition, please note the UPC and sales numbers included in the attachment for the City of Whitehorse are only available on a billed energy basis. As the forecast for lighting is not calculated on a community basis, but rather on an aggregate basis for all of Yukon Electrical by rate code, Yukon Electrical is not able to provide a forecast solely for the City of Whitehorse. Yukon Electrical does not have a breakdown of data for customers who use electricity for space heating and those who do not.

(c) Please refer to YUB-YECL-57 Attachments 1 to 21.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue for the City of Whitehorse (Billed Basis)

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013 Existing	Test Period 2014 Existing	Test Period 2015 Existing
1	**Residential**								
2	Customers (average during year)	9,500	9,704	9,906	10,185	10,525	10,792	10,975	11,161
3	Sales in MWh	101,946	106,262	104,737	115,951	119,094	120,955	123,009	125,097
4	MWh sales per customer	10.73	10.95	10.57	11.39	11.32	11.21	11.21	11.21
7	**Commercial**								
8	Customers (average during year)	1,782	1,814	1,869	1,926	1,988	2,031	2,055	2,087
9	Sales in MWh	120,275	121,391	123,231	130,152	133,847	136,539	139,517	142,565
10	MWh sales per customer	67.51	66.92	65.93	67.57	67.32	67.23	67.89	68.31
11	**Industrial**								
12	Customers (average during year)	-	-	-	-	-	1	1	1
13	Sales in MWh	-	-	-	-	-	1,025	4,620	4,620
14	MWh sales per customer	-	-	-	-	-	1,025	4,620	4,620
15	**Street Lights**								
16	Sales in MWh	2,688	2,731	2,843	2,865	2,919			
17	**Private Lights**								
18	Sales in MWh	428	401	403	390	372			
19	**Total Company - Retail - Primary**								
20	Customers	11,282	11,518	11,775	12,111	12,513	12,823	13,030	13,248
21	Sales in MWh	225,337	230,785	231,214	249,358	256,231	258,519	267,146	272,282
22	**Secondary Sales**								
23	Customers (average during year)	22	21	21	14	2	-	-	-
24	Sales in MWh	18,053	16,843	10,153	552	1,993	-	-	-
25	MWh sales per customer	820.59	802.05	483.48	39.43	996.50	-	-	-
26	**Total Company**								
27	Customers	11,304	11,539	11,796	12,125	12,515	12,823	13,030	13,248
28	Sales in MWh	243,390	247,628	241,367	249,910	258,224	257,494	262,526	267,662

CW-YECL-3

Reference: Sales and Revenue, Application, page 2-6

In its Application, YECL states:

> Twelve new large commercial customers (demand > 100kW) are anticipated to be added during the test period; eleven in Whitehorse and one in Watson Lake. Yukon Electrical has considered each of these new large customers individually, and forecast the load each will bring to the system each year based on the start-up time and other pertinent information provided by the customer. To forecast Whitehorse and Watson Lake commercial energy sales over the test period, Yukon Electrical has first determined the base energy sales for each community, which is forecast by multiplying the forecast customer counts (excluding the new large customer additions), by the corresponding community base year UPC forecast. The base year UPC for Watson Lake is obtained based on the most recent three-year actual UPC. For Whitehorse, the 2012 normalized UPC is used as a base year UPC. This is because of conversion of several secondary commercial customers to primary in recent years makes it inappropriate to use a three-year average. The commercial energy sales for Whitehorse and Watson Lake are then calculated by adding the base energy sales in each year to the specific energy sales of the new large commercial additions.

The City requires information to assess the forecast of Commercial sales.

Request:

(a) Please provide the forecast and timing of the sales to the twelve new large customers.

(b) Please provide the calculation of the forecast of commercial sales by community, before the impact of the twelve new customers is added. Please provide the response in Excel format, with formulae and links intact.

(c) Please reconcile the information provided in response to (a) and (b) above to the total commercial sales in Schedule 2.1

Response:

(a - c) On page 2-6 of the Application, Yukon Electrical inadvertently reported that there were 12 large commercial customers expected to be added during the test period. In fact, the correct number is 10 large commercial customers (9 in Whitehorse and 1 in Watson Lake) are expected to be added during the test period. Please refer to CW-YECL-3 Attachment 1 for the requested details on the commercial sales forecast.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Summary of 2013 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy (MWh)	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2013	2013				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	79	2,454			79	2,454	1.017	2,497
Carcross	62	1,241			62	1,241	1.013	1,257
Haines Junction	128	3,576			128	3,576	1.014	3,627
Teslin	71	1,942			71	1,942	1.021	1,984
Upper Liard	14.128	233			14	233	1.024	239
Destruction Bay	48	867			48	867	1.018	883
Whitehorse (1)	2,028	135,543	3	996	2,031	136,539	1.017	138,909
Beaver Creek	36	882			36	882	1.013	893
Watson Lake	173	6,221	1	210	174	6,431	1.017	6,538
Old Crow	41	866			41	866	1.017	881
Keno City	124,405	10			124,405	10	1.003	10
Stewart Crossing	264,010	20			264,010	20	1.021	21
Lower Post B.C.	248,741	18			248,741	18	1.019	18
Ross River	1,252,611	26			1,252,611	26	1.017	27
Pelly Crossing	1,009,884	36			1,009,884	36	1.021	37
Swift River	176,776	13			176,776	13	1.019	13
Tagish	255,389	11			255,389	11	1.021	11
Marsh Lake	347,164	14			347,164	14	1.020	14
Deep Creek	40,869	20			40,869	20	1.002	20
Minto Landing	68,476	22			68,476	22	1.018	22
TOTAL GENERAL S	3,791,004	154,014		1,206	3,791,007	155,220		157,899

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table B: Summary of 2014 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2014	2014				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	80	2,489			80	2,489	1.017	2,532
Carcross	63	1,258			63	1,258	1.013	1,274
Haines Junction	130	3,626			130	3,626	1.014	3,678
Teslin	72	1,971			72	1,971	1.021	2,013
Upper Liard	14.377	237			14	237	1.024	243
Destruction Bay	49	880			49	880	1.018	895
Whitehorse (1)	2,050	137,009	5	2,508	2,055	139,517	1.017	141,939
Beaver Creek	37	897			37	897	1.013	909
Watson Lake	174	6,270	1	420	175	6,690	1.017	6,801
Old Crow	42	878			42	878	1.017	893
Keno City	126,255	10			126,255	10	1.003	10
Stewart Crossing	267,646	20			267,646	20	1.021	21
Lower Post B.C.	251,608	18			251,608	18	1.019	18
Ross River	1,270,836	26			1,270,836	26	1.017	27
Pelly Crossing	1,024,101	36			1,024,101	36	1.021	37
Swift River	179,237	13			179,237	13	1.019	13
Tagish	258,857	11			258,857	11	1.021	11
Marsh Lake	351,759	14			351,759	14	1.020	14
Deep Creek	41,435	20			41,435	20	1.002	20
Minto Landing	75,428	22			75,428	22	1.018	22
TOTAL GENERAL S	3,849,873	155,704		2,928	3,849,879	158,631.9		161,369

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table C: Summary of 2015 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2015	2015				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	81	2,525			81	2,525	1.017	2,569
Carcross	64	1,276			64	1,276	1.013	1,293
Haines Junction	132	3,678			132	3,678	1.014	3,731
Teslin	73	2,002			73	2,002	1.021	2,045
Upper Liard	14.716	243			15	243	1.024	249
Destruction Bay	50	893			50	893	1.018	909
Whitehorse (1)	2,079	138,950	7	3,615	2,087	142,565	1.017	145,040
Beaver Creek	38	914			38	914	1.013	926
Watson Lake	177	6,366	1	420	178	6,786	1.017	6,899
Old Crow	42	891			42	891	1.017	906
Keno City	128,296	10			128,296	10	1.003	10
Stewart Crossing	271,640	20			271,640	20	1.021	21
Lower Post B.C.	255,393	18			255,393	18	1.019	18
Ross River	1,290,344	26			1,290,344	26	1.017	27
Pelly Crossing	1,039,400	36			1,039,400	36	1.021	37
Swift River	181,938	13			181,938	13	1.019	13
Tagish	262,612	11			262,612	11	1.021	11
Marsh Lake	356,711	14			356,711	14	1.020	14
Deep Creek	42,194	20			42,194	20	1.002	20
Minto Landing	82,922	22			82,922	22	1.018	22
TOTAL GENERAL S	3,914,200	157,927		4,035	3,914,208	161,962		164,757

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Specific Customer Adds

	2013 Additional Energy				2014 Additional Energy			2015 Additional Energy		Customers			2013 Add'l Energy	Customers	
	Cust 1 (kWh)	Cust 2 (kWh)	Cust 3 (kWh)	Cust 4 (kWh)	Cust 5 (kWh)	Cust 6 (kWh)	Cust 7 (kWh)	Cust 8 (kWh)	Cust 9 (kWh)	Total	Average		Cust 1 (kWh)	Total	Average
Jan-13										-		Jan-13		-	
Feb-13										-		Feb-13		-	
Mar-13										-		Mar-13		-	
Apr-13	22,630									1		Apr-13		-	
May-13	22,630									1		May-13		-	
Jun-13	22,630	16,164	48,493	48,493						4		Jun-13		-	
Jul-13	22,630	16,164	48,493	48,493						4		Jul-13	35,040	1	
Aug-13	22,630	16,164	48,493	48,493						4		Aug-13	35,040	1	
Sep-13	22,630	16,164	48,493	48,493						4		Sep-13	35,040	1	
Oct-13	22,630	16,164	48,493	48,493						4		Oct-13	35,040	1	
Nov-13	22,630	16,164	48,493	48,493						4		Nov-13	35,040	1	
Dec-13	22,630	16,164	48,493	48,493						4	3	Dec-13	35,040	1	1
Jan-14	22,630	22,630	67,890	67,890						4		Jan-14	35,040	1	
Feb-14	22,630	22,630	67,890	67,890						4		Feb-14	35,040	1	
Mar-14	22,630	22,630	67,890	67,890						4		Mar-14	35,040	1	
Apr-14	22,630	22,630	67,890	67,890						4		Apr-14	35,040	1	
May-14	22,630	22,630	67,890	67,890						4		May-14	35,040	1	
Jun-14	22,630	22,630	67,890	67,890						4		Jun-14	35,040	1	
Jul-14	22,630	22,630	67,890	67,890						4		Jul-14	35,040	1	
Aug-14	22,630	22,630	67,890	67,890						4		Aug-14	35,040	1	
Sep-14	22,630	22,630	67,890	67,890						4		Sep-14	35,040	1	
Oct-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Oct-14	35,040	1	
Nov-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Nov-14	35,040	1	
Dec-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7	5	Dec-14	35,040	1	1
Jan-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jan-15	35,040	1	
Feb-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Feb-15	35,040	1	
Mar-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Mar-15	35,040	1	
Apr-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Apr-15	35,040	1	
May-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		May-15	35,040	1	
Jun-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jun-15	35,040	1	
Jul-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jul-15	35,040	1	
Aug-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Aug-15	35,040	1	
Sep-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Sep-15	35,040	1	
Oct-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Oct-15	35,040	1	
Nov-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260	25,550	25,550	9		Nov-15	35,040	1	
Dec-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260	25,550	25,550	9	7	Dec-15	35,040	1	1
Annual Totals										**Total**		**Annual Totals**			
2013-F	203,670	113,150	339,450	339,450	-	-	-	-	-	995,720		2013-F	210,240		
2014-F	271,560	271,560	814,680	814,680	67,890	131,400	135,780	-	-	2,507,550		2014-F	420,480		
2015-F	271,560	271,560	814,680	814,680	271,560	525,600	543,120	51,100	51,100	3,614,960		2015-F	420,480		

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Jan-98	1,649	6,510	6,406	10,735,219	1165.7
Feb-98	1,636	5,639	5,803	9,225,150	719.1
Mar-98	1,648	5,698	5,738	9,389,723	756.6
Apr-98	1,645	5,168	5,217	8,501,373	458.6
May-98	1,666	4,594	4,667	7,653,575	270.6
Jun-98	1,655	4,661	4,720	7,714,120	119.5
Jul-98	1,643	5,020	5,022	8,247,191	111.6
Aug-98	1,644	4,590	4,557	7,545,936	189.2
Sep-98	1,642	4,964	4,946	8,151,291	327.8
Oct-98	1,654	4,837	4,813	8,000,105	557.7
Nov-98	1,663	5,346	5,381	8,890,864	792.3
Dec-98	1,672	5,404	5,288	9,036,054	1051.8
Jan-99	1,670	6,310	6,180	10,537,212	1,183
Feb-99	1,662	5,781	5,579	9,607,851	976
Mar-99	1,665	5,636	5,709	9,383,909	734
Apr-99	1,671	5,330	5,307	8,906,205	509
May-99	1,673	4,619	4,519	7,726,882	392
Jun-99	1,665	4,951	4,961	8,243,728	154
Jul-99	1,664	4,693	4,699	7,808,371	109
Aug-99	1,649	4,814	4,843	7,938,088	146
Sep-99	1,661	4,777	4,782	7,933,808	311
Oct-99	1,631	4,767	4,825	7,774,298	500
Nov-99	1,628	5,700	5,735	9,279,565	793
Dec-99	1,643	5,409	5,588	8,886,266	844
Jan-00	1,645	6,270	6,283	10,313,342	1,083
Feb-00	1,646	5,618	5,760	9,247,783	735
Mar-00	1,651	5,373	5,552	8,870,464	659
Apr-00	1,644	5,136	5,104	8,443,072	516
May-00	1,656	4,910	4,824	8,130,814	382
Jun-00	1,639	5,036	5,019	8,253,857	173
Jul-00	1,643	5,239	5,198	8,608,146	142
Aug-00	1,639	4,599	4,522	7,537,654	220
Sep-00	1,653	4,689	4,634	7,751,449	354
Oct-00	1,637	5,076	5,078	8,308,993	539
Nov-00	1,650	5,164	5,344	8,521,038	691
Dec-00	1,643	5,333	5,321	8,761,532	978
Jan-01	1,632	6,240	6,768	10,184,241	723
Feb-01	1,635	5,374	5,332	8,786,468	864
Mar-01	1,651	5,576	5,604	9,206,099	765
Apr-01	1,649	5,256	5,236	8,666,356	507
May-01	1,644	4,875	4,777	8,014,257	390
Jun-01	1,626	5,068	5,059	8,240,335	167
Jul-01	1,628	4,858	4,821	7,909,557	140
Aug-01	1,624	4,690	4,727	7,615,762	140
Sep-01	1,642	4,701	4,710	7,718,506	309
Oct-01	1,641	4,777	4,731	7,839,267	573
Nov-01	1,647	5,163	5,162	8,504,116	818
Dec-01	1,651	6,072	5,894	10,024,659	1,095
Jan-02	1,652	6,629	6,853	10,951,080	936

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Feb-02	1,644	5,650	5,664	9,288,783	825
Mar-02	1,653	5,655	5,462	9,348,209	921
Apr-02	1,650	5,824	5,596	9,609,869	653
May-02	1,657	4,990	4,933	8,268,251	362
Jun-02	1,665	4,981	4,960	8,292,927	176
Jul-02	1,660	4,834	4,809	8,024,723	131
Aug-02	1,656	5,117	5,093	8,474,109	183
Sep-02	1,649	4,695	4,696	7,741,980	314
Oct-02	1,674	4,779	4,917	8,000,187	444
Nov-02	1,671	5,344	5,678	8,930,222	583
Dec-02	1,660	5,252	5,429	8,717,761	845
Jan-03	1,659	6,122	6,269	10,156,110	989
Feb-03	1,663	5,473	5,584	9,100,970	757
Mar-03	1,675	5,560	5,490	9,313,508	835
Apr-03	1,663	5,639	5,609	9,377,998	514
May-03	1,687	4,799	4,740	8,096,541	364
Jun-03	1,655	5,197	5,152	8,601,844	193
Jul-03	1,662	4,875	4,916	8,102,548	84
Aug-03	1,658	4,831	4,810	8,010,231	181
Sep-03	1,664	4,981	4,918	8,288,208	359
Oct-03	1,657	4,913	5,019	8,140,663	467
Nov-03	1,670	5,714	5,632	9,542,613	875
Dec-03	1,675	6,035	6,118	10,108,563	912
Jan-04	1,675	6,331	6,096	10,605,074	1,258
Feb-04	1,669	5,889	6,084	9,827,952	697
Mar-04	1,678	5,723	5,769	9,603,827	754
Apr-04	1,673	5,679	5,717	9,500,870	467
May-04	1,683	4,923	4,993	8,284,611	273
Jun-04	1,685	5,261	5,371	8,864,143	84
Jul-04	1,675	5,388	5,443	9,024,437	74
Aug-04	1,673	5,198	5,290	8,696,604	102
Sep-04	1,689	4,971	4,897	8,396,465	368
Oct-04	1,704	4,903	4,903	8,353,942	541
Nov-04	1,700	5,552	5,691	9,438,374	720
Dec-04	1,692	5,929	6,029	10,031,917	900
Jan-05	1,695	6,545	6,441	11,094,349	1,166
Feb-05	1,703	5,834	5,890	9,934,638	795
Mar-05	1,713	5,579	5,824	9,556,887	614
Apr-05	1,701	5,451	5,508	9,271,969	453
May-05	1,711	5,227	5,320	8,942,598	257
Jun-05	1,699	4,921	4,930	8,360,369	154
Jul-05	1,703	5,073	5,045	8,639,652	133
Aug-05	1,700	5,043	5,065	8,573,524	151
Sep-05	1,719	5,110	5,133	8,784,835	299
Oct-05	1,710	5,023	5,033	8,589,960	535
Nov-05	1,720	5,827	5,905	10,022,927	763
Dec-05	1,707	5,698	5,948	9,726,467	794
Jan-06	1,712	6,646	6,640	11,377,324	1,096
Feb-06	1,710	5,773	5,792	9,872,441	821

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Mar-06	1,715	6,397	6,225	10,971,322	906
Apr-06	1,696	5,960	5,923	10,107,989	519
May-06	1,748	4,761	4,725	8,321,928	347
Jun-06	1,730	5,286	5,269	9,145,264	173
Jul-06	1,736	5,287	5,279	9,178,255	118
Aug-06	1,741	5,008	4,957	8,719,688	202
Sep-06	1,747	5,008	5,036	8,748,995	296
Oct-06	1,744	5,297	5,326	9,237,260	521
Nov-06	1,754	5,718	5,226	10,029,371	1,162
Dec-06	1,753	6,174	6,382	10,823,542	824
Jan-07	1,752	6,817	7,074	11,943,556	912
Feb-07	1,762	6,297	6,063	11,095,328	999
Mar-07	1,770	6,667	6,426	11,800,895	954
Apr-07	1,760	6,031	6,004	10,614,723	512
May-07	1,774	5,036	5,036	8,933,347	322
Jun-07	1,754	5,129	5,158	8,995,924	141
Jul-07	1,761	5,518	5,533	9,716,489	102
Aug-07	1,768	4,950	4,967	8,752,313	154
Sep-07	1,773	5,037	5,047	8,931,422	308
Oct-07	1,774	4,990	4,986	8,851,952	544
Nov-07	1,778	5,813	5,944	10,334,697	725
Dec-07	1,771	5,865	5,723	10,386,533	1,070
Jan-08	1,768	6,899	6,868	12,196,869	1,114
Feb-08	1,765	6,600	6,429	11,649,227	955
Mar-08	1,765	5,840	5,912	10,307,654	735
Apr-08	1,768	6,124	6,089	10,826,351	517
May-08	1,783	4,996	5,016	8,907,241	308
Jun-08	1,809	5,010	4,918	9,063,550	226
Jul-08	1,791	4,791	4,705	8,580,173	173
Aug-08	1,794	5,501	5,470	9,869,120	188
Sep-08	1,802	4,961	4,956	8,939,459	319
Oct-08	1,803	4,959	4,928	8,940,719	563
Nov-08	1,758	6,095	6,144	10,714,995	783
Dec-08	1,773	5,798	5,490	10,280,063	1,186
Jan-09	1,789	7,570	7,506	13,543,505	1,138
Feb-09	1,794	5,991	5,819	10,747,772	955
Mar-09	1,802	6,296	6,177	11,344,681	869
Apr-09	1,803	5,849	5,817	10,544,854	515
May-09	1,801	5,030	5,017	9,059,430	331
Jun-09	1,806	4,873	4,897	8,800,466	144
Jul-09	1,811	5,336	5,408	9,663,288	63
Aug-09	1,821	5,044	5,055	9,185,022	158
Sep-09	1,827	4,767	4,780	8,709,101	306
Oct-09	1,831	4,920	4,919	9,008,981	542
Nov-09	1,841	5,672	5,723	10,443,040	782
Dec-09	1,843	5,611	5,648	10,340,528	943
Jan-10	1,855	6,873	7,018	12,750,313	991
Feb-10	1,854	5,793	6,014	10,739,999	679
Mar-10	1,853	5,694	5,878	10,550,465	656

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Apr-10	1,872	5,852	5,898	10,955,417	461
May-10	1,882	5,064	5,106	9,529,520	292
Jun-10	1,878	5,075	5,059	9,530,854	172
Jul-10	1,888	4,885	4,879	9,223,514	117
Aug-10	1,883	4,927	4,955	9,277,423	146
Sep-10	1,796	5,003	4,978	8,985,101	332
Oct-10	1,873	5,088	5,117	9,529,688	520
Nov-10	1,902	5,773	5,915	10,980,325	718
Dec-10	1,894	5,902	5,628	11,178,789	1,163
Jan-11	1,895	7,318	7,436	13,868,531	1,010
Feb-11	1,901	5,885	5,784	11,187,292	906
Mar-11	1,904	6,638	6,472	12,639,624	902
Apr-11	1,914	5,638	5,612	10,790,977	511
May-11	1,920	5,379	5,416	10,328,077	296
Jun-11	1,926	5,025	5,025	9,677,894	161
Jul-11	1,924	4,935	4,914	9,494,900	128
Aug-11	1,933	4,867	4,793	9,408,841	218
Sep-11	1,944	5,020	5,001	9,758,502	329
Oct-11	1,937	5,224	5,264	10,119,093	513
Nov-11	1,956	5,624	5,454	11,001,007	936
Dec-11	1,961	6,057	6,335	11,877,662	775
Jan-12	1,964	7,288	7,252	14,314,241	1,118
Feb-12	1,964	6,086	6,267	11,953,663	708
Mar-12	1,971	5,990	6,032	11,806,946	756
Apr-12	1,967	5,947	6,007	11,697,409	451
May-12	1,993	5,350	5,309	10,663,094	351
Jun-12	1,970	5,063	5,007	9,974,100	200
Jul-12	2,003	4,956	4,918	9,927,438	140
Aug-12	2,005	4,808	4,819	9,639,853	158
Sep-12	1,997	4,626	4,666	9,238,345	287
Oct-12	2,005	5,242	5,113	10,510,210	631
Nov-12	2,013	5,613	5,395	11,298,741	970
Dec-12	2,005	6,396	6,072	12,822,998	1,197
Jan-13	2,015		7,252	14,614,192	
Feb-13	2,017		6,267	12,641,246	
Mar-13	2,020		6,032	12,185,918	
Apr-13	2,018		6,007	12,124,591	
May-13	2,030		5,309	10,778,962	
Jun-13	2,028		5,007	10,152,628	
Jul-13	2,031		4,918	9,987,718	
Aug-13	2,035		4,819	9,806,486	
Sep-13	2,038		4,666	9,508,869	
Oct-13	2,038		5,113	10,422,317	
Nov-13	2,036		5,395	10,984,488	
Dec-13	2,032		6,072	12,335,800	
Jan-14	2,034		7,252	14,750,718	
Feb-14	2,036		6,267	12,760,376	
Mar-14	2,040		6,032	12,302,686	
Apr-14	2,037		6,007	12,239,596	

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial	Customers	Actual	Normalized	Energy	(Whitehorse)
Customers		UPC (kWh)	UPC (kWh)	(kWh)	MHDD
May-14	2,051		5,309	10,887,279	
Jun-14	2,048		5,007	10,253,419	
Jul-14	2,051		4,918	10,088,437	
Aug-14	2,057		4,819	9,911,974	
Sep-14	2,061		4,666	9,617,151	
Oct-14	2,063		5,113	10,546,320	
Nov-14	2,064		5,395	11,137,279	
Dec-14	2,061		6,072	12,514,241	
Jan-15	2,064		7,252	14,964,260	
Feb-15	2,065		6,267	12,945,216	
Mar-15	2,069		6,032	12,481,103	
Apr-15	2,067		6,007	12,416,972	
May-15	2,080		5,309	11,045,711	
Jun-15	2,078		5,007	10,402,494	
Jul-15	2,081		4,918	10,235,282	
Aug-15	2,086		4,819	10,051,552	
Sep-15	2,089		4,666	9,747,997	
Oct-15	2,090		5,113	10,684,650	
Nov-15	2,090		5,395	11,277,934	
Dec-15	2,091		6,072	12,696,929	
	Customers (annual avg)			Fcst Energy (kWh)	
2013-F	2,028			135,543,216	
2014-F	2,050			137,009,476	
2015-F	2,079			138,950,098	

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Carmacks

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	68	235,146	3,458
Feb-08	68	221,848	3,262
Mar-08	68	185,467	2,727
Apr-08	70	166,283	2,375
May-08	72	167,662	2,329
Jun-08	72	158,276	2,198
Jul-08	72	120,216	1,670
Aug-08	72	153,928	2,138
Sep-08	71	146,743	2,067
Oct-08	71	176,987	2,493
Nov-08	71	178,315	2,511
Dec-08	70	181,659	2,595
Jan-09	69	208,430	3,021
Feb-09	69	188,110	2,726
Mar-09	66	122,959	1,863
Apr-09	69	131,892	1,911
May-09	68	183,187	2,694
Jun-09	70	183,187	2,617
Jul-09	72	153,753	2,135
Aug-09	69	138,156	2,002
Sep-09	71	147,089	2,072
Oct-09	72	164,608	2,286
Nov-09	71	158,313	2,230
Dec-09	70	158,313	2,262
Jan-10	73	280,962	3,849
Feb-10	71	184,747	2,602
Mar-10	72	180,907	2,513
Apr-10	73	165,009	2,260
May-10	75	162,319	2,164
Jun-10	76	228,585	3,008
Jul-10	77	164,320	2,134
Aug-10	79	85,479	1,082
Sep-10	57	83,926	1,472
Oct-10	77	298,012	3,870
Nov-10	79	223,677	2,831
Dec-10	78	205,672	2,637
Jan-11	76	268,896	3,538
Feb-11	77	220,736	2,867
Mar-11	74	226,823	3,065
Apr-11	77	165,843	2,154
May-11	77	222,799	2,893
Jun-11	79	155,785	1,972
Jul-11	79	184,241	2,332
Aug-11	80	176,149	2,202
Sep-11	79	212,191	2,686
Oct-11	80	197,727	2,472
Nov-11	79	235,750	2,984
Dec-11	79	218,199	2,762
Jan-12	80	255,628	3,195
Feb-12	77	209,845	2,725
Mar-12	75	247,316	3,298
Apr-12	79	204,654	2,591
May-12	76	173,845	2,287
Jun-12	77	192,728	2,503
Jul-12	77	164,369	2,135
Aug-12	79	195,417	2,474
Sep-12	79	164,256	2,079
Oct-12	80	211,916	2,649
Nov-12	78	219,960	2,820
Dec-12	78	205,098	2,629

Carcross

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	47	92,691	1,972
Feb-08	47	102,377	2,178
Mar-08	45	78,164	1,737
Apr-08	48	80,697	1,681
May-08	51	79,027	1,550
Jun-08	52	79,150	1,522
Jul-08	55	86,515	1,573
Aug-08	57	98,673	1,731
Sep-08	56	84,268	1,505
Oct-08	64	82,157	1,284
Nov-08	52	75,940	1,460
Dec-08	49	90,002	1,837
Jan-09	48	103,483	2,156
Feb-09	46	97,483	2,119
Mar-09	48	89,376	1,862
Apr-09	47	86,000	1,830
May-09	56	117,181	2,093
Jun-09	56	79,644	1,422
Jul-09	57	95,273	1,671
Aug-09	57	84,624	1,485
Sep-09	56	87,061	1,555
Oct-09	54	92,626	1,715
Nov-09	52	68,826	1,324
Dec-09	48	81,965	1,708
Jan-10	48	93,702	1,952
Feb-10	48	97,073	2,022
Mar-10	48	83,495	1,739
Apr-10	48	79,796	1,662
May-10	57	76,503	1,342
Jun-10	57	82,284	1,444
Jul-10	58	87,157	1,503
Aug-10	58	82,690	1,426
Sep-10	58	102,151	1,761
Oct-10	56	81,327	1,452
Nov-10	50	91,347	1,827
Dec-10	48	95,210	1,984
Jan-11	48	128,469	2,676
Feb-11	50	93,657	1,873
Mar-11	50	131,485	2,630
Apr-11	57	101,202	1,775
May-11	58	86,082	1,484
Jun-11	61	101,218	1,659
Jul-11	60	83,273	1,388
Aug-11	60	84,352	1,406
Sep-11	59	93,479	1,584
Nov-11	60	81,050	1,351
Nov-11	54	78,677	1,457
Dec-11	55	113,921	2,071
Jan-12	56	91,494	1,634
Feb-12	56	122,699	2,191
Mar-12	56	98,185	1,753
Apr-12	59	87,421	1,482
May-12	59	85,896	1,456
Jun-12	61	86,001	1,410
Jul-12	63	90,330	1,434
Aug-12	64	85,103	1,330
Sep-12	63	77,070	1,223
Oct-12	62	76,217	1,229
Nov-12	62	88,296	1,424
Dec-12	62	99,243	1,601

Haines Junction

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	121	325,052	2,686
Feb-08	121	294,177	2,431
Mar-08	121	290,346	2,400
Apr-08	125	272,487	2,180
May-08	129	223,379	1,732
Jun-08	132	282,643	2,141
Jul-08	133	256,985	1,932
Aug-08	134	269,699	2,013
Sep-08	134	255,772	1,909
Oct-08	133	241,134	1,813
Nov-08	126	270,331	2,145
Dec-08	123	318,205	2,587
Jan-09	127	361,816	2,849
Feb-09	127	281,823	2,219
Mar-09	127	348,569	2,745
Apr-09	129	270,194	2,095
May-09	132	269,973	2,045
Jun-09	133	262,992	1,977
Jul-09	133	286,741	2,156
Aug-09	133	271,919	2,045
Sep-09	134	245,373	1,831
Oct-09	134	262,557	1,959
Nov-09	128	311,882	2,437
Dec-09	127	284,686	2,242
Jan-10	126	350,767	2,784
Feb-10	126	265,556	2,108
Mar-10	125	294,885	2,359
Apr-10	127	283,266	2,230
May-10	132	277,130	2,099
Jun-10	130	278,384	2,141
Jul-10	132	258,243	1,956
Aug-10	134	248,639	1,856
Sep-10	133	263,572	1,982
Oct-10	133	254,275	1,912
Nov-10	128	313,316	2,448
Dec-10	128	292,149	2,282
Jan-11	128	389,779	3,045
Feb-11	128	320,788	2,506
Mar-11	127	351,046	2,764
Apr-11	128	301,473	2,355
May-11	134	286,001	2,134
Jun-11	134	267,487	1,996
Jul-11	132	272,609	2,065
Aug-11	132	253,808	1,923
Sep-11	132	271,118	2,054
Nov-11	131	298,662	2,280
Nov-11	128	310,832	2,428
Dec-11	128	359,882	2,812
Jan-12	129	349,457	2,709
Feb-12	129	385,698	2,990
Mar-12	129	339,723	2,634
Apr-12	129	356,615	2,764
May-12	129	228,425	1,771
Jun-12	127	333,608	2,627
Jul-12	125	304,523	2,436
Aug-12	128	241,354	1,886
Sep-12	128	310,488	2,426
Oct-12	133	251,153	1,888
Nov-12	129	319,377	2,476
Dec-12	127	347,738	2,738

The Yukon Electrical Company Limited
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Carmacks

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	78	275,445	3,527
Feb-13	78	213,519	2,731
Mar-13	78	231,528	2,958
Apr-13	78	182,934	2,335
May-13	78	192,037	2,448
Jun-13	79	195,847	2,494
Jul-13	79	172,959	2,200
Aug-13	79	151,027	1,919
Sep-13	79	163,800	2,079
Oct-13	79	236,362	2,997
Nov-13	79	227,271	2,879
Dec-13	79	211,522	2,676
Jan-14	79	279,150	3,527
Feb-14	79	216,412	2,731
Mar-14	79	234,690	2,958
Apr-14	79	185,451	2,335
May-14	80	194,698	2,448
Jun-14	80	198,580	2,494
Jul-14	80	175,390	2,200
Aug-14	80	153,166	1,919
Sep-14	80	166,135	2,079
Oct-14	80	239,756	2,997
Nov-14	80	230,557	2,879
Dec-14	80	214,602	2,676
Jan-15	80	283,217	3,527
Feb-15	80	219,568	2,731
Mar-15	80	238,115	2,958
Apr-15	81	188,159	2,335
May-15	81	197,544	2,448
Jun-15	81	201,485	2,494
Jul-15	81	177,957	2,200
Aug-15	81	155,409	1,919
Sep-15	81	168,571	2,079
Oct-15	81	243,273	2,997
Nov-15	81	233,942	2,879
Dec-15	81	217,755	2,676

	Customers	Energy	Avg UPC
2013-F	79	2,454,250	31,239
2014-F	80	2,488,587	31,238
2015-F	81	2,524,995	31,238

Carcross

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	62	129,563	2,087
Feb-13	62	126,061	2,029
Mar-13	62	126,942	2,041
Apr-13	62	102,112	1,640
May-13	62	88,978	1,427
Jun-13	62	93,869	1,504
Jul-13	62	90,048	1,441
Aug-13	63	86,745	1,387
Sep-13	63	95,345	1,523
Oct-13	63	84,239	1,344
Nov-13	63	98,459	1,569
Dec-13	63	118,400	1,885
Jan-14	63	131,259	2,087
Feb-14	63	127,724	2,029
Mar-14	63	128,630	2,041
Apr-14	63	103,480	1,640
May-14	63	90,178	1,427
Jun-14	63	95,145	1,504
Jul-14	63	91,281	1,441
Aug-14	63	87,941	1,387
Sep-14	63	96,669	1,523
Oct-14	64	85,417	1,344
Nov-14	64	99,845	1,569
Dec-14	64	120,078	1,885
Jan-15	64	133,168	2,087
Feb-15	64	129,583	2,029
Mar-15	64	130,503	2,041
Apr-15	64	104,988	1,640
May-15	64	91,493	1,427
Jun-15	64	96,534	1,504
Jul-15	64	92,614	1,441
Aug-15	64	89,226	1,387
Sep-15	64	98,083	1,523
Oct-15	64	86,667	1,344
Nov-15	65	101,308	1,569
Dec-15	65	121,839	1,885

	Customers	Energy	Avg UPC
2013-F	62	1,240,761	19,872
2014-F	63	1,257,646	19,872
2015-F	64	1,276,005	19,872

Haines Junction

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	127	361,849	2,846
Feb-13	127	322,613	2,535
Mar-13	127	329,479	2,586
Apr-13	128	312,559	2,450
May-13	128	255,625	2,002
Jun-13	128	288,297	2,255
Jul-13	128	275,537	2,153
Aug-13	128	241,933	1,888
Sep-13	128	276,305	2,154
Oct-13	128	260,291	2,027
Nov-13	129	315,091	2,451
Dec-13	129	336,042	2,611
Jan-14	129	366,780	2,846
Feb-14	129	327,043	2,535
Mar-14	129	334,036	2,586
Apr-14	129	316,915	2,450
May-14	130	259,213	2,002
Jun-14	130	292,374	2,255
Jul-14	130	279,461	2,153
Aug-14	130	245,403	1,888
Sep-14	130	280,297	2,154
Oct-14	130	264,077	2,027
Nov-14	130	319,706	2,451
Dec-14	131	340,999	2,611
Jan-15	131	372,012	2,846
Feb-15	131	331,712	2,535
Mar-15	131	338,809	2,586
Apr-15	131	321,447	2,450
May-15	131	262,923	2,002
Jun-15	132	296,561	2,255
Jul-15	132	283,467	2,153
Aug-15	132	248,924	1,888
Sep-15	132	284,321	2,154
Oct-15	132	267,872	2,027
Nov-15	132	324,304	2,451
Dec-15	132	345,906	2,611

	Customers	Energy	Avg UPC
2013-F	128	3,575,620	27,950
2014-F	130	3,626,304	27,949
2015-F	132	3,678,258	27,949

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Teslin

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	66	220,160	3,336
Feb-08	66	219,812	3,330
Mar-08	66	147,735	2,238
Apr-08	72	135,464	1,881
May-08	76	165,074	2,172
Jun-08	79	122,645	1,552
Jul-08	78	131,460	1,685
Aug-08	78	149,971	1,923
Sep-08	78	125,108	1,604
Oct-08	82	145,567	1,775
Nov-08	67	180,680	2,697
Dec-08	69	193,687	2,807
Jan-09	68	233,026	3,427
Feb-09	61	206,649	3,388
Mar-09	70	200,059	2,858
Apr-09	74	191,713	2,591
May-09	77	158,150	2,054
Jun-09	77	122,767	1,594
Jul-09	77	147,605	1,917
Aug-09	77	132,777	1,724
Sep-09	77	136,847	1,777
Oct-09	78	177,110	2,271
Nov-09	70	186,573	2,665
Dec-09	69	186,388	2,701
Jan-10	69	232,990	3,377
Feb-10	69	217,890	3,158
Mar-10	68	197,759	2,908
Apr-10	72	200,870	2,790
May-10	74	127,137	1,718
Jun-10	77	132,809	1,725
Jul-10	77	135,649	1,762
Aug-10	77	120,304	1,562
Sep-10	75	161,500	2,153
Oct-10	76	128,809	1,695
Nov-10	69	150,694	2,184
Dec-10	68	207,231	3,048
Jan-11	67	216,649	3,234
Feb-11	68	172,050	2,530
Mar-11	68	204,761	3,011
Apr-11	72	156,663	2,176
May-11	74	157,402	2,127
Jun-11	77	125,865	1,635
Jul-11	77	155,130	2,015
Aug-11	76	126,337	1,662
Sep-11	76	148,165	1,950
Nov-11	77	141,950	1,844
Nov-11	73	172,572	2,364
Dec-11	73	182,419	2,499
Jan-12	73	231,512	3,171
Feb-12	74	184,836	2,498
Mar-12	71	201,328	2,836
Apr-12	69	161,008	2,333
May-12	76	128,792	1,695
Jun-12	77	150,812	1,959
Jul-12	78	133,981	1,718
Aug-12	78	124,243	1,593
Sep-12	78	151,839	1,947
Oct-12	79	144,168	1,825
Nov-12	73	214,556	2,939
Dec-12	70	208,877	2,984

Upper Liard

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	14	28,244	2,017
Feb-08	14	29,677	2,120
Mar-08	14	20,208	1,443
Apr-08	14	22,381	1,599
May-08	19	17,788	936
Jun-08	19	18,135	954
Jul-08	20	24,171	1,209
Aug-08	20	23,774	1,189
Sep-08	19	24,663	1,298
Oct-08	18	19,458	1,081
Nov-08	14	18,681	1,334
Dec-08	14	20,331	1,452
Jan-09	14	32,633	2,331
Feb-09	14	26,898	1,921
Mar-09	14	27,402	1,957
Apr-09	14	24,739	1,767
May-09	19	15,031	791
Jun-09	19	22,465	1,182
Jul-09	21	23,789	1,133
Aug-09	19	27,439	1,444
Sep-09	21	23,822	1,134
Oct-09	19	26,213	1,380
Nov-09	15	29,293	1,953
Dec-09	15	25,715	1,714
Jan-10	15	29,599	1,973
Feb-10	15	24,797	1,653
Mar-10	15	24,754	1,650
Apr-10	14	23,362	1,669
May-10	19	17,357	914
Jun-10	19	21,359	1,124
Jul-10	20	21,826	1,091
Aug-10	20	23,776	1,189
Sep-10	10	2,611	261
Oct-10	17	39,592	2,329
Nov-10	13	18,982	1,460
Dec-10	13	19,420	1,494
Jan-11	13	22,395	1,723
Feb-11	13	17,524	1,348
Mar-11	13	20,527	1,579
Apr-11	13	14,425	1,110
May-11	18	18,447	1,025
Jun-11	20	19,697	985
Jul-11	21	22,834	1,087
Aug-11	21	27,406	1,305
Sep-11	21	21,359	1,017
Nov-11	20	23,058	1,153
Nov-11	15	23,920	1,595
Dec-11	14	22,716	1,623
Jan-12	14	29,037	2,074
Feb-12	14	21,334	1,524
Mar-12	14	20,493	1,464
Apr-12	14	19,770	1,412
May-12	19	19,550	1,029
Jun-12	20	23,487	1,174
Jul-12	21	26,968	1,284
Aug-12	21	25,365	1,208
Sep-12	20	22,888	1,144
Oct-12	21	25,309	1,205
Nov-12	20	26,678	1,334
Dec-12	14	32,204	2,300

Destruction Bay

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	49	98,811	2,017
Feb-08	49	86,537	1,766
Mar-08	49	85,684	1,749
Apr-08	50	82,964	1,659
May-08	49	70,133	1,431
Jun-08	48	81,207	1,692
Jul-08	48	64,509	1,344
Aug-08	48	78,590	1,637
Sep-08	48	72,037	1,501
Oct-08	50	62,500	1,250
Nov-08	48	82,307	1,715
Dec-08	46	76,655	1,666
Jan-09	45	96,095	2,135
Feb-09	47	93,758	1,995
Mar-09	47	67,529	1,437
Apr-09	47	85,901	1,828
May-09	48	52,407	1,092
Jun-09	48	63,275	1,318
Jul-09	48	63,426	1,321
Aug-09	48	60,050	1,251
Sep-09	48	65,148	1,357
Oct-09	48	54,086	1,127
Nov-09	49	66,276	1,353
Dec-09	49	70,872	1,446
Jan-10	49	96,239	1,964
Feb-10	49	73,570	1,501
Mar-10	48	67,624	1,409
Apr-10	49	81,295	1,659
May-10	50	58,964	1,179
Jun-10	51	65,892	1,292
Jul-10	49	65,993	1,347
Aug-10	49	61,048	1,246
Sep-10	48	69,838	1,455
Oct-10	48	59,250	1,234
Nov-10	50	66,576	1,332
Dec-10	48	71,893	1,498
Jan-11	48	92,114	1,919
Feb-11	48	76,842	1,601
Mar-11	48	80,407	1,675
Apr-11	48	82,157	1,712
May-11	50	77,539	1,551
Jun-11	51	66,668	1,307
Jul-11	49	56,949	1,162
Aug-11	49	59,188	1,208
Sep-11	48	68,672	1,431
Nov-11	46	58,423	1,270
Nov-11	51	72,617	1,424
Dec-11	49	80,264	1,638
Jan-12	49	117,375	2,395
Feb-12	49	85,389	1,743
Mar-12	49	88,354	1,803
Apr-12	49	74,158	1,513
May-12	49	60,613	1,237
Jun-12	49	64,301	1,312
Jul-12	47	56,219	1,196
Aug-12	51	72,895	1,429
Sep-12	50	78,441	1,569
Oct-12	48	67,509	1,406
Nov-12	48	72,022	1,500
Dec-12	48	81,645	1,701

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Teslin

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	70	228,510	3,261
Feb-13	70	191,455	2,729
Mar-13	70	205,013	2,918
Apr-13	70	171,125	2,433
May-13	70	130,030	1,847
Jun-13	70	124,972	1,773
Jul-13	71	129,262	1,831
Aug-13	71	113,480	1,606
Sep-13	71	142,667	2,017
Oct-13	71	126,632	1,788
Nov-13	71	176,985	2,496
Dec-13	71	201,884	2,843
Jan-14	71	231,797	3,261
Feb-14	71	194,230	2,729
Mar-14	71	208,006	2,918
Apr-14	71	173,642	2,433
May-14	71	131,956	1,847
Jun-14	72	126,837	1,773
Jul-14	72	131,205	1,831
Aug-14	72	115,198	1,606
Sep-14	72	144,841	2,017
Oct-14	72	128,575	1,788
Nov-14	72	179,720	2,496
Dec-14	72	205,024	2,843
Jan-15	72	235,418	3,261
Feb-15	72	197,267	2,729
Mar-15	72	211,261	2,918
Apr-15	72	176,360	2,433
May-15	73	134,024	1,847
Jun-15	73	128,826	1,773
Jul-15	73	133,263	1,831
Aug-15	73	117,006	1,606
Sep-15	73	147,117	2,017
Oct-15	73	130,596	1,788
Nov-15	73	182,547	2,496
Dec-15	73	208,251	2,843

	Customers	Energy	Avg UPC
2013-F	71	1,942,015	27,530
2014-F	72	1,971,033	27,529
2015-F	73	2,001,936	27,529

Upper Liard

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	14	26,965	1,923
Feb-13	14	21,176	1,508
Mar-13	14	21,993	1,564
Apr-13	14	19,665	1,397
May-13	14	13,945	989
Jun-13	14	15,451	1,094
Jul-13	14	16,318	1,154
Aug-13	14	17,468	1,234
Sep-13	14	11,448	808
Oct-13	14	22,180	1,562
Nov-13	14	20,797	1,463
Dec-13	14	25,703	1,806
Jan-14	14	27,422	1,923
Feb-14	14	21,537	1,508
Mar-14	14	22,371	1,564
Apr-14	14	20,006	1,397
May-14	14	14,188	989
Jun-14	14	15,723	1,094
Jul-14	14	16,607	1,154
Aug-14	14	17,780	1,234
Sep-14	14	11,653	808
Oct-14	14	22,580	1,562
Nov-14	14	21,175	1,463
Dec-14	14	26,174	1,806
Jan-15	15	28,070	1,923
Feb-15	15	22,046	1,508
Mar-15	15	22,900	1,564
Apr-15	15	20,479	1,397
May-15	15	14,523	989
Jun-15	15	16,094	1,094
Jul-15	15	17,000	1,154
Aug-15	15	18,200	1,234
Sep-15	15	11,929	808
Oct-15	15	23,114	1,562
Nov-15	15	21,675	1,463
Dec-15	15	26,792	1,806

	Customers	Energy	Avg UPC
2013-F	14	233,109	16,500
2014-F	14	237,215	16,500
2015-F	15	242,820	16,500

Destruction Bay

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	48	100,570	2,093
Feb-13	48	77,695	1,615
Mar-13	48	78,460	1,629
Apr-13	48	78,501	1,628
May-13	48	63,833	1,322
Jun-13	48	63,010	1,304
Jul-13	48	59,754	1,235
Aug-13	48	62,694	1,294
Sep-13	48	71,999	1,485
Oct-13	49	63,284	1,304
Nov-13	49	68,943	1,419
Dec-13	49	78,442	1,612
Jan-14	49	101,950	2,093
Feb-14	49	78,769	1,615
Mar-14	49	79,553	1,629
Apr-14	49	79,602	1,628
May-14	49	64,735	1,322
Jun-14	49	63,907	1,304
Jul-14	49	60,610	1,235
Aug-14	49	63,599	1,294
Sep-14	49	73,046	1,485
Oct-14	49	64,211	1,304
Nov-14	49	69,960	1,419
Dec-14	49	79,606	1,612
Jan-15	49	103,541	2,093
Feb-15	50	79,999	1,615
Mar-15	50	80,796	1,629
Apr-15	50	80,847	1,628
May-15	50	65,748	1,322
Jun-15	50	64,908	1,304
Jul-15	50	61,560	1,235
Aug-15	50	64,596	1,294
Sep-15	50	74,192	1,485
Oct-15	50	65,219	1,304
Nov-15	50	71,059	1,419
Dec-15	50	80,858	1,612

	Customers	Energy	Avg UPC
2013-F	48	867,184	17,934
2014-F	49	879,549	17,934
2015-F	50	893,324	17,933

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Beaver Creek

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-08	44	89,358	2,031
Feb-08	44	133,371	3,031
Mar-08	44	38,006	864
Apr-08	52	79,993	1,538
May-08	53	118,707	2,240
Jun-08	53	79,837	1,506
Jul-08	51	114,280	2,241
Aug-08	51	132,679	2,602
Sep-08	49	88,448	1,805
Oct-08	48	68,743	1,432
Nov-08	41	81,156	1,979
Dec-08	41	82,977	2,024
Jan-09	42	102,810	2,448
Feb-09	41	86,079	2,099
Mar-09	42	84,699	2,017
Apr-09	45	80,255	1,783
May-09	51	77,033	1,510
Jun-09	51	93,100	1,825
Jul-09	51	129,021	2,530
Aug-09	51	106,975	2,098
Sep-09	51	103,498	2,029
Oct-09	50	111,981	2,240
Nov-09	41	38,788	946
Dec-09	41	77,194	1,883
Jan-10	39	99,620	2,554
Feb-10	39	82,939	2,127
Mar-10	39	78,339	2,009
Apr-10	43	74,945	1,743
May-10	49	88,043	1,797
Jun-10	51	107,992	2,117
Jul-10	53	128,036	2,416
Aug-10	53	125,452	2,367
Sep-10	53	92,687	1,749
Oct-10	52	94,315	1,814
Nov-10	45	81,812	1,818
Dec-10	41	75,385	1,839
Jan-11	41	110,795	2,702
Feb-11	41	80,033	1,952
Mar-11	41	91,959	2,243
Apr-11	52	85,935	1,653
May-11	53	123,375	2,328
Jun-11	53	100,289	1,892
Jul-11	52	115,620	2,223
Aug-11	54	127,427	2,360
Sep-11	54	113,926	2,110
Nov-11	50	90,446	1,809
Nov-11	44	78,777	1,790
Dec-11	41	86,463	2,109
Jan-12	39	90,079	2,310
Feb-12	39	76,311	1,957
Mar-12	39	78,695	2,018
Apr-12	50	72,969	1,459
May-12	50	78,673	1,573
Jun-12	50	117,501	2,350
Jul-12	50	103,170	2,063
Aug-12	50	115,724	2,314
Sep-12	50	86,264	1,725
Oct-12	50	78,314	1,566
Nov-12	43	83,120	1,933
Dec-12	36	73,580	2,044

Watson Lake **BASE (Before Large Adds)**

Base Commercial monthly	Customers	Energy (kWh)	Actual UPC (kWh)
Jan-08	166	572,441	3,448
Feb-08	165	590,669	3,580
Mar-08	165	544,032	3,297
Apr-08	166	502,010	3,024
May-08	175	491,312	2,807
Jun-08	182	469,175	2,578
Jul-08	180	501,315	2,785
Aug-08	181	522,406	2,886
Sep-08	188	437,685	2,328
Oct-08	168	434,163	2,584
Nov-08	163	532,668	3,268
Dec-08	165	529,892	3,211
Jan-09	165	612,999	3,715
Feb-09	167	544,359	3,260
Mar-09	163	518,737	3,182
Apr-09	162	496,967	3,068
May-09	169	467,605	2,767
Jun-09	176	445,940	2,534
Jul-09	177	494,796	2,795
Aug-09	175	464,386	2,654
Sep-09	177	441,280	2,493
Nov-09	167	500,060	2,994
Nov-09	164	635,272	3,874
Dec-09	166	446,774	2,691
Jan-10	159	618,993	3,893
Feb-10	161	590,130	3,665
Mar-10	156	522,517	3,349
Apr-10	165	533,742	3,235
May-10	178	441,090	2,478
Jun-10	185	439,015	2,373
Jul-10	184	484,601	2,634
Aug-10	184	455,164	2,474
Sep-10	157	401,724	2,559
Oct-10	175	545,857	3,119
Nov-10	174	524,193	3,013
Dec-10	171	564,653	3,302
Jan-11	171	655,153	3,831
Feb-11	171	538,445	3,149
Mar-11	171	601,947	3,520
Apr-11	170	507,810	2,987
May-11	181	481,162	2,658
Jun-11	188	460,157	2,448
Jul-11	186	444,037	2,387
Aug-11	190	366,835	1,931
Sep-11	185	457,783	2,475
Nov-11	183	485,944	2,655
Nov-11	178	551,841	3,100
Dec-11	176	593,611	3,373
Jan-12	176	721,619	4,100
Feb-12	174	584,459	3,359
Mar-12	174	618,441	3,554
Apr-12	172	543,793	3,162
May-12	178	525,476	2,952
Jun-12	185	515,897	2,789
Jul-12	186	450,262	2,421
Aug-12	183	492,001	2,689
Sep-12	186	568,132	3,054
Oct-12	179	327,900	1,832
Nov-12	173	611,768	3,536
Dec-12	169	643,981	3,811

Old Crow

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-08	36	67,068	1,863
Feb-08	36	82,504	2,292
Mar-08	36	67,205	1,867
Apr-08	36	61,010	1,695
May-08	36	64,410	1,789
Jun-08	38	65,153	1,715
Jul-08	39	46,313	1,188
Aug-08	38	63,222	1,664
Sep-08	38	50,827	1,338
Oct-08	36	46,442	1,290
Nov-08	36	77,581	2,155
Dec-08	36	70,871	1,969
Jan-09	35	85,987	2,457
Feb-09	35	63,846	1,824
Mar-09	36	77,262	2,146
Apr-09	36	74,060	2,057
May-09	37	69,284	1,873
Jun-09	36	52,610	1,461
Jul-09	36	66,046	1,835
Aug-09	35	45,682	1,305
Sep-09	35	44,662	1,276
Oct-09	35	66,900	1,911
Nov-09	34	59,153	1,740
Dec-09	35	69,048	1,973
Jan-10	35	82,489	2,357
Feb-10	35	64,923	1,855
Mar-10	35	65,174	1,862
Apr-10	35	80,462	2,299
May-10	35	53,747	1,536
Jun-10	35	54,364	1,553
Jul-10	35	47,590	1,360
Aug-10	39	46,323	1,188
Sep-10	40	47,352	1,184
Oct-10	40	59,598	1,490
Nov-10	40	66,045	1,651
Dec-10	39	66,299	1,700
Jan-11	40	87,427	2,186
Feb-11	40	79,874	1,997
Mar-11	40	73,122	1,828
Apr-11	40	73,497	1,837
May-11	40	72,699	1,817
Jun-11	40	62,070	1,552
Jul-11	40	61,581	1,540
Aug-11	40	55,150	1,379
Sep-11	40	61,418	1,535
Nov-11	40	59,221	1,481
Nov-11	40	68,823	1,721
Dec-11	40	82,704	2,068
Jan-12	40	81,822	2,046
Feb-12	40	73,746	1,844
Mar-12	40	96,431	2,411
Apr-12	40	80,562	2,014
May-12	40	65,105	1,628
Jun-12	41	74,146	1,808
Jul-12	41	52,307	1,276
Aug-12	41	71,273	1,738
Sep-12	40	50,379	1,259
Oct-12	40	64,873	1,622
Nov-12	41	65,249	1,591
Dec-12	41	111,378	2,717

The Yukon Electrical Company Limited
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Beaver Creek

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	36	90,925	2,522
Feb-13	36	72,628	2,012
Mar-13	36	75,551	2,090
Apr-13	36	58,587	1,618
May-13	36	68,858	1,899
Jun-13	36	76,962	2,120
Jul-13	36	81,224	2,234
Aug-13	36	85,446	2,347
Sep-13	36	67,855	1,861
Oct-13	37	63,144	1,730
Nov-13	37	67,527	1,847
Dec-13	37	73,111	1,997
Jan-14	37	92,471	2,522
Feb-14	37	73,873	2,012
Mar-14	37	76,855	2,090
Apr-14	37	59,605	1,618
May-14	37	70,064	1,899
Jun-14	37	78,318	2,120
Jul-14	37	82,666	2,234
Aug-14	37	86,974	2,347
Sep-14	37	69,076	1,861
Oct-14	37	64,288	1,730
Nov-14	37	68,758	1,847
Dec-14	37	74,453	1,997
Jan-15	37	94,170	2,522
Feb-15	37	75,257	2,012
Mar-15	37	78,292	2,090
Apr-15	38	60,718	1,618
May-15	38	71,370	1,899
Jun-15	38	79,777	2,120
Jul-15	38	84,203	2,234
Aug-15	38	88,588	2,347
Sep-15	38	70,356	1,861
Oct-15	38	65,478	1,730
Nov-15	38	70,029	1,847
Dec-15	38	75,827	1,997

	Customers	Energy	Avg UPC
2013-F	36	881,817	24,273
2014-F	37	897,400	24,272
2015-F	38	914,066	24,272

Watson Lake **BASE (Before Large Adds)**

Base Commercial monthly	Customers	Energy (kWh)	Actual UPC (kWh)
Jan-13	173	682,658	3,941
Feb-13	173	586,652	3,391
Mar-13	173	601,111	3,475
Apr-13	173	541,115	3,128
May-13	173	466,437	2,696
Jun-13	173	438,805	2,536
Jul-13	173	429,142	2,481
Aug-13	173	409,027	2,364
Sep-13	173	466,392	2,696
Oct-13	173	438,639	2,535
Nov-13	173	556,429	3,216
Dec-13	173	604,658	3,495
Jan-14	173	682,740	3,941
Feb-14	173	588,138	3,391
Mar-14	174	603,395	3,475
Apr-14	174	543,857	3,128
May-14	174	469,390	2,696
Jun-14	174	442,139	2,536
Jul-14	175	432,946	2,481
Aug-14	175	413,171	2,364
Sep-14	175	471,708	2,696
Oct-14	175	444,194	2,535
Nov-14	175	564,181	3,216
Dec-14	176	613,847	3,495
Jan-15	176	692,466	3,941
Feb-15	176	597,266	3,391
Mar-15	176	612,748	3,475
Apr-15	177	552,276	3,128
May-15	177	476,648	2,696
Jun-15	177	448,967	2,536
Jul-15	177	439,623	2,481
Aug-15	177	419,536	2,364
Sep-15	178	478,965	2,696
Oct-15	178	451,019	2,535
Nov-15	178	572,839	3,216
Dec-15	178	623,255	3,495

	Customers (ann	Fcst Energy (kW	Avg UPC
2013-F	173	6,221,065	35,956
2014-F	174	6,269,708	35,945
2015-F	177	6,365,608	35,944

Old Crow

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	41	90,135	2,196
Feb-13	41	78,008	1,898
Mar-13	41	83,654	2,034
Apr-13	41	84,424	2,050
May-13	41	68,443	1,660
Jun-13	41	67,592	1,638
Jul-13	41	57,497	1,392
Aug-13	41	59,350	1,435
Sep-13	41	54,913	1,326
Oct-13	41	63,450	1,531
Nov-13	41	68,648	1,654
Dec-13	42	89,782	2,161
Jan-14	42	91,331	2,196
Feb-14	42	79,051	1,898
Mar-14	42	84,780	2,034
Apr-14	42	85,569	2,050
May-14	42	69,378	1,660
Jun-14	42	68,523	1,638
Jul-14	42	58,294	1,392
Aug-14	42	60,178	1,435
Sep-14	42	55,685	1,326
Oct-14	42	64,348	1,531
Nov-14	42	69,627	1,654
Dec-14	42	91,071	2,161
Jan-15	42	92,657	2,196
Feb-15	42	80,210	1,898
Mar-15	42	86,022	2,034
Apr-15	42	86,821	2,050
May-15	42	70,392	1,660
Jun-15	42	69,523	1,638
Jul-15	42	59,143	1,392
Aug-15	43	61,054	1,435
Sep-15	43	56,495	1,326
Oct-15	43	65,283	1,531
Nov-15	43	70,637	1,654
Dec-15	43	92,391	2,161

	Customers	Energy	Avg UPC
2013-F	41	865,896	20,970
2014-F	42	877,835	20,969
2015-F	42	890,628	20,969

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Keno City

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	11	19,277	1,752
Feb-08	11	19,144	1,740
Mar-08	11	14,851	1,350
Apr-08	11	9,727	884
May-08	11	5,882	535
Jun-08	11	4,866	442
Jul-08	11	5,426	493
Aug-08	12	6,258	522
Sep-08	11	5,385	490
Oct-08	11	4,558	414
Nov-08	11	7,196	654
Dec-08	11	7,448	677
Jan-09	12	14,606	1,217
Feb-09	11	9,932	903
Mar-09	12	11,109	926
Apr-09	12	13,738	1,145
May-09	12	10,971	914
Jun-09	12	7,822	652
Jul-09	12	3,779	315
Aug-09	12	6,962	580
Sep-09	12	6,283	524
Oct-09	12	6,629	552
Nov-09	12	8,182	682
Dec-09	12	7,687	641
Jan-10	12	9,754	813
Feb-10	12	7,471	623
Mar-10	12	21,058	1,755
Apr-10	12	13,505	1,125
May-10	12	4,195	350
Jun-10	12	6,250	521
Jul-10	12	6,012	501
Aug-10	12	5,785	482
Sep-10	12	7,396	616
Oct-10	12	6,470	539
Nov-10	12	8,609	717
Dec-10	12	9,265	772
Jan-11	12	12,956	1,080
Feb-11	12	10,034	836
Mar-11	12	10,436	870
Apr-11	12	14,435	1,203
May-11	12	14,749	1,229
Jun-11	12	13,170	1,098
Jul-11	12	8,117	676
Aug-11	12	18,860	1,572
Sep-11	13	6,064	466
Nov-11	13	21,125	1,625
Nov-11	13	12,407	954
Dec-11	13	8,980	691
Jan-12	13	26,504	2,039
Feb-12	13	14,215	1,093
Mar-12	13	16,764	1,290
Apr-12	13	14,064	1,082
May-12	13	8,864	682
Jun-12	12	10,133	844
Jul-12	13	1,565	120
Aug-12	13	5,589	430
Sep-12	13	6,240	480
Oct-12	13	5,779	445
Nov-12	13	8,695	669
Dec-12	12	7,198	600

Stewart Crossing

Residential		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	15	36,240	2,416
Feb-08	14	44,894	3,207
Mar-08	14	28,784	2,056
Apr-08	14	16,642	1,189
May-08	15	26,842	1,789
Jun-08	14	19,982	1,427
Jul-08	14	13,104	936
Aug-08	14	19,541	1,396
Sep-08	15	15,633	1,042
Oct-08	14	20,461	1,462
Nov-08	14	25,597	1,828
Dec-08	13	26,703	2,054
Jan-09	11	36,807	3,346
Feb-09	14	36,052	2,575
Mar-09	14	27,967	1,998
Apr-09	15	25,031	1,669
May-09	15	19,941	1,329
Jun-09	14	16,842	1,203
Jul-09	13	18,775	1,444
Aug-09	14	17,707	1,265
Sep-09	14	16,260	1,161
Oct-09	15	19,057	1,270
Nov-09	15	20,545	1,370
Dec-09	15	24,637	1,642
Jan-10	10	25,358	2,536
Feb-10	13	26,715	2,055
Mar-10	13	23,031	1,772
Apr-10	13	22,521	1,732
May-10	11	17,272	1,570
Jun-10	13	14,021	1,079
Jul-10	12	14,894	1,241
Aug-10	12	15,434	1,286
Sep-10	11	15,516	1,411
Oct-10	14	33,981	2,427
Nov-10	16	27,780	1,736
Dec-10	16	33,270	2,079
Jan-11	16	37,114	2,320
Feb-11	16	32,155	2,010
Mar-11	16	35,227	2,202
Apr-11	15	23,627	1,575
May-11	14	21,575	1,541
Jun-11	14	16,071	1,148
Jul-11	15	16,872	1,125
Aug-11	16	18,348	1,147
Sep-11	16	20,879	1,305
Nov-11	16	18,378	1,149
Nov-11	16	24,599	1,537
Dec-11	13	26,291	2,022
Jan-12	14	34,076	2,434
Feb-12	14	26,323	1,880
Mar-12	13	40,429	3,110
Apr-12	13	9,050	696
May-12	9	14,773	1,641
Jun-12	13	22,093	1,699
Jul-12	13	16,595	1,277
Aug-12	13	14,994	1,153
Sep-12	13	13,689	1,053
Oct-12	13	17,805	1,370
Nov-12	13	30,666	2,359
Dec-12	13	23,891	1,838

Lower Post BC

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	12	20,658	1,722
Feb-08	12	20,430	1,703
Mar-08	12	19,032	1,586
Apr-08	12	19,402	1,617
May-08	12	16,739	1,395
Jun-08	11	9,833	894
Jul-08	13	9,117	701
Aug-08	13	8,646	665
Sep-08	15	10,710	714
Oct-08	13	12,541	965
Nov-08	13	16,435	1,264
Dec-08	13	20,043	1,542
Jan-09	13	24,397	1,877
Feb-09	12	19,373	1,614
Mar-09	13	20,139	1,549
Apr-09	13	18,011	1,385
May-09	13	13,818	1,063
Jun-09	13	12,242	942
Jul-09	13	12,620	971
Aug-09	13	10,974	844
Sep-09	14	14,572	1,041
Oct-09	14	15,466	1,105
Nov-09	15	20,437	1,362
Dec-09	15	26,563	1,771
Jan-10	15	32,126	2,142
Feb-10	14	24,626	1,759
Mar-10	14	23,598	1,686
Apr-10	15	22,159	1,477
May-10	15	14,719	981
Jun-10	15	13,642	909
Jul-10	15	12,079	805
Aug-10	15	10,519	701
Sep-10	13	9,895	761
Oct-10	11	10,514	956
Nov-10	14	30,914	2,208
Dec-10	13	24,941	1,919
Jan-11	13	25,325	1,948
Feb-11	12	18,667	1,556
Mar-11	12	23,229	1,936
Apr-11	12	16,035	1,336
May-11	12	12,800	1,067
Jun-11	12	14,218	1,185
Jul-11	12	9,863	822
Aug-11	12	11,714	976
Sep-11	13	14,390	1,107
Nov-11	13	17,891	1,376
Nov-11	13	23,053	1,773
Dec-11	13	25,053	1,927
Jan-12	13	31,371	2,413
Feb-12	13	26,952	2,073
Mar-12	14	26,567	1,898
Apr-12	14	23,101	1,650
May-12	14	19,762	1,412
Jun-12	14	18,378	1,313
Jul-12	14	16,520	1,180
Aug-12	14	16,064	1,147
Sep-12	14	15,662	1,119
Oct-12	14	20,696	1,478
Nov-12	14	22,725	1,623
Dec-12	14	30,647	2,189

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Keno City

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	12	15,744	1,310
Feb-13	12	10,233	851
Mar-13	12	15,712	1,305
Apr-13	12	13,706	1,137
May-13	12	9,096	754
Jun-13	12	9,921	821
Jul-13	12	5,234	433
Aug-13	12	10,029	828
Sep-13	12	6,318	521
Oct-13	12	10,559	870
Nov-13	12	9,485	780
Dec-13	12	8,368	688
Jan-14	12	15,970	1,310
Feb-14	12	10,381	851
Mar-14	12	15,941	1,305
Apr-14	12	13,907	1,137
May-14	12	9,230	754
Jun-14	12	10,069	821
Jul-14	12	5,313	433
Aug-14	12	10,181	828
Sep-14	12	6,414	521
Oct-14	12	10,720	870
Nov-14	12	9,631	780
Dec-14	12	8,498	688
Jan-15	12	16,272	1,310
Feb-15	12	10,546	851
Mar-15	12	16,193	1,305
Apr-15	12	14,127	1,137
May-15	12	9,376	754
Jun-15	12	10,228	821
Jul-15	12	5,397	433
Aug-15	12	10,341	828
Sep-15	13	6,515	521
Oct-15	13	10,889	870
Nov-15	13	9,782	780
Dec-15	13	8,631	688

	Customers	Energy	Avg UPC
2013-F	12	124,405	10,288
2014-F	12	126,255	10,287
2015-F	12	128,296	10,288

Stewart Crossing

Residential		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	13	31,622	2,430
Feb-13	13	25,818	1,982
Mar-13	13	30,795	2,361
Apr-13	13	17,425	1,335
May-13	13	20,708	1,584
Jun-13	13	17,124	1,309
Jul-13	13	15,905	1,214
Aug-13	13	15,677	1,195
Sep-13	13	16,491	1,256
Oct-13	13	21,665	1,648
Nov-13	13	24,702	1,878
Dec-13	13	26,077	1,980
Jan-14	13	32,041	2,430
Feb-14	13	26,163	1,982
Mar-14	13	31,209	2,361
Apr-14	13	17,662	1,335
May-14	13	20,991	1,584
Jun-14	13	17,360	1,309
Jul-14	13	16,126	1,214
Aug-14	13	15,896	1,195
Sep-14	13	16,723	1,256
Oct-14	13	21,972	1,648
Nov-14	13	25,054	1,878
Dec-14	13	26,451	1,980
Jan-15	13	32,602	2,430
Feb-15	13	26,546	1,982
Mar-15	13	31,666	2,361
Apr-15	13	17,920	1,335
May-15	13	21,297	1,584
Jun-15	13	17,613	1,309
Jul-15	13	16,361	1,214
Aug-15	13	16,127	1,195
Sep-15	14	16,966	1,256
Oct-15	14	22,291	1,648
Nov-15	14	25,418	1,878
Dec-15	14	26,834	1,980

	Customers	Energy	Avg UPC
2013-F	13	264,010	20,165
2014-F	13	267,646	20,164
2015-F	13	271,640	20,166

Lower Post BC

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	14	30,381	2,168
Feb-13	14	24,872	1,796
Mar-13	14	26,098	1,840
Apr-13	14	21,107	1,488
May-13	14	16,359	1,153
Jun-13	14	16,111	1,136
Jul-13	14	13,274	936
Aug-13	14	13,358	942
Sep-13	14	14,124	996
Oct-13	14	18,018	1,270
Nov-13	14	26,503	1,868
Dec-13	14	28,537	2,012
Jan-14	14	30,788	2,168
Feb-14	14	25,539	1,796
Mar-14	14	26,192	1,840
Apr-14	14	21,209	1,488
May-14	14	16,458	1,153
Jun-14	14	16,228	1,136
Jul-14	14	13,387	936
Aug-14	14	13,487	942
Sep-14	14	14,277	996
Oct-14	14	18,236	1,270
Nov-14	14	26,855	1,868
Dec-14	14	28,951	2,012
Jan-15	14	31,321	2,168
Feb-15	14	25,918	1,796
Mar-15	14	26,580	1,840
Apr-15	14	21,523	1,488
May-15	14	16,701	1,153
Jun-15	14	16,467	1,136
Jul-15	15	13,584	936
Aug-15	15	13,686	942
Sep-15	15	14,487	996
Oct-15	15	18,503	1,270
Nov-15	15	27,249	1,868
Dec-15	15	29,375	2,012

	Customers	Energy	Avg UPC
2013-F	14	248,741	17,587
2014-F	14	251,608	17,598
2015-F	15	255,393	17,600

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Ross River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	46	114,224	2,483
Feb-08	46	146,930	3,194
Mar-08	43	104,852	2,438
Apr-08	46	97,281	2,115
May-08	46	106,530	2,316
Jun-08	46	80,827	1,757
Jul-08	46	71,189	1,548
Aug-08	46	83,888	1,824
Sep-08	46	84,846	1,844
Oct-08	46	93,934	2,042
Nov-08	46	96,656	2,101
Dec-08	46	125,362	2,725
Jan-09	45	137,387	3,053
Feb-09	46	94,202	2,048
Mar-09	46	119,217	2,592
Apr-09	46	101,227	2,201
May-09	46	90,002	1,957
Jun-09	46	77,208	1,678
Jul-09	46	75,007	1,631
Aug-09	46	89,016	1,935
Sep-09	46	50,462	1,097
Oct-09	46	100,197	2,178
Nov-09	46	88,146	1,916
Dec-09	46	120,466	2,619
Jan-10	46	137,669	2,993
Feb-10	47	113,244	2,409
Mar-10	46	115,089	2,502
Apr-10	45	112,834	2,507
May-10	45	79,657	1,770
Jun-10	45	85,169	1,893
Jul-10	45	86,646	1,925
Aug-10	46	85,599	1,861
Sep-10	46	82,613	1,796
Oct-10	46	89,508	1,946
Nov-10	46	96,741	2,103
Dec-10	46	123,366	2,682
Jan-11	46	136,826	2,974
Feb-11	45	114,211	2,538
Mar-11	46	107,244	2,331
Apr-11	45	109,005	2,422
May-11	44	78,303	1,780
Jun-11	44	73,675	1,674
Jul-11	43	78,956	1,836
Aug-11	43	74,081	1,723
Sep-11	45	80,053	1,779
Nov-11	46	80,189	1,743
Nov-11	47	89,330	1,901
Dec-11	47	93,650	1,993
Jan-12	47	175,496	3,734
Feb-12	49	132,363	2,701
Mar-12	49	145,810	2,976
Apr-12	47	101,554	2,161
May-12	50	100,742	2,015
Jun-12	50	103,358	2,067
Jul-12	51	90,261	1,770
Aug-12	50	97,662	1,953
Sep-12	50	86,122	1,722
Oct-12	48	98,996	2,062
Nov-12	48	124,903	2,602
Dec-12	47	119,613	2,545

Pelly Crossing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	29	90,812	3,131
Feb-08	29	108,137	3,729
Mar-08	29	81,804	2,821
Apr-08	29	59,285	2,044
May-08	30	75,053	2,502
Jun-08	29	58,602	2,021
Jul-08	30	44,911	1,497
Aug-08	30	60,469	2,016
Sep-08	30	65,290	2,176
Oct-08	30	89,703	2,990
Nov-08	30	81,690	2,723
Dec-08	30	73,897	2,463
Jan-09	29	85,513	2,949
Feb-09	29	65,603	2,262
Mar-09	29	111,365	3,840
Apr-09	28	82,326	2,940
May-09	30	131,105	4,370
Jun-09	30	68,339	2,278
Jul-09	31	74,106	2,391
Aug-09	32	60,731	1,898
Sep-09	31	77,585	2,503
Oct-09	30	75,941	2,531
Nov-09	31	90,630	2,924
Dec-09	31	82,561	2,663
Jan-10	29	105,601	3,641
Feb-10	31	87,952	2,837
Mar-10	30	84,203	2,807
Apr-10	31	90,283	2,912
May-10	30	71,896	2,397
Jun-10	31	72,670	2,344
Jul-10	30	73,172	2,439
Aug-10	32	70,189	2,193
Sep-10	26	65,567	2,522
Oct-10	31	96,555	3,115
Nov-10	31	138,307	4,462
Dec-10	30	62,920	2,097
Jan-11	29	129,575	4,468
Feb-11	29	100,874	3,478
Mar-11	28	102,885	3,674
Apr-11	29	92,837	3,201
May-11	30	104,604	3,487
Jun-11	30	69,469	2,316
Jul-11	29	77,856	2,685
Aug-11	30	70,242	2,341
Sep-11	29	82,164	2,833
Nov-11	29	72,958	2,516
Nov-11	27	89,845	3,328
Dec-11	28	82,380	2,942
Jan-12	29	122,556	4,226
Feb-12	27	85,292	3,159
Mar-12	28	101,698	3,632
Apr-12	28	79,907	2,854
May-12	29	75,037	2,587
Jun-12	26	74,738	2,875
Jul-12	29	62,125	2,142
Aug-12	29	70,267	2,423
Sep-12	29	68,366	2,357
Oct-12	28	76,625	2,737
Nov-12	28	119,676	4,274
Dec-12	28	88,012	3,143

Swift River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	13	26,310	2,024
Feb-08	13	21,945	1,688
Mar-08	13	18,796	1,446
Apr-08	13	20,063	1,543
May-08	13	15,812	1,216
Jun-08	13	12,746	980
Jul-08	13	12,899	992
Aug-08	13	13,740	1,057
Sep-08	13	12,483	960
Oct-08	13	13,163	1,013
Nov-08	13	21,162	1,628
Dec-08	13	20,924	1,610
Jan-09	12	23,479	1,957
Feb-09	13	21,573	1,659
Mar-09	13	24,221	1,863
Apr-09	13	17,441	1,342
May-09	13	14,149	1,088
Jun-09	13	11,604	893
Jul-09	12	12,459	1,038
Aug-09	13	12,475	960
Sep-09	13	12,245	942
Oct-09	13	11,214	863
Nov-09	13	18,184	1,399
Dec-09	13	16,676	1,283
Jan-10	12	20,342	1,695
Feb-10	12	16,017	1,335
Mar-10	14	15,800	1,129
Apr-10	12	11,941	995
May-10	14	13,788	985
Jun-10	15	5,934	396
Jul-10	15	6,425	428
Aug-10	14	8,304	593
Sep-10	11	9,447	859
Oct-10	13	10,679	821
Nov-10	13	18,199	1,400
Dec-10	14	18,494	1,321
Jan-11	13	21,181	1,629
Feb-11	14	17,628	1,259
Mar-11	14	20,929	1,495
Apr-11	14	15,964	1,140
May-11	14	10,835	774
Jun-11	14	9,352	668
Jul-11	14	8,736	624
Aug-11	14	10,780	770
Sep-11	14	9,790	699
Nov-11	14	14,352	1,025
Nov-11	14	16,597	1,186
Dec-11	14	17,469	1,248
Jan-12	14	23,487	1,678
Feb-12	14	17,642	1,260
Mar-12	14	17,026	1,216
Apr-12	14	16,382	1,170
May-12	14	12,813	915
Jun-12	14	12,781	913
Jul-12	14	10,368	741
Aug-12	14	12,957	926
Sep-12	14	10,066	719
Oct-12	14	14,818	1,058
Nov-12	14	17,318	1,237
Dec-12	14	18,437	1,317

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Ross River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	47	152,162	3,234
Feb-13	47	120,108	2,550
Mar-13	47	122,767	2,603
Apr-13	47	111,599	2,363
May-13	47	87,684	1,855
Jun-13	47	88,883	1,878
Jul-13	47	87,363	1,844
Aug-13	47	87,549	1,846
Sep-13	47	83,857	1,766
Oct-13	48	91,151	1,917
Nov-13	48	104,811	2,202
Dec-13	48	114,676	2,406
Jan-14	48	154,294	3,234
Feb-14	48	121,804	2,550
Mar-14	48	124,513	2,603
Apr-14	48	113,198	2,363
May-14	48	88,950	1,855
Jun-14	48	90,176	1,878
Jul-14	48	88,642	1,844
Aug-14	48	88,840	1,846
Sep-14	48	85,102	1,766
Oct-14	48	92,514	1,917
Nov-14	48	106,389	2,202
Dec-14	48	116,415	2,406
Jan-15	48	156,621	3,234
Feb-15	49	123,690	2,550
Mar-15	49	126,438	2,603
Apr-15	49	114,946	2,363
May-15	49	90,321	1,855
Jun-15	49	91,565	1,878
Jul-15	49	90,006	1,844
Aug-15	49	90,205	1,846
Sep-15	49	86,408	1,766
Oct-15	49	93,932	1,917
Nov-15	49	108,018	2,202
Dec-15	49	118,195	2,406

	Customers	Energy	Avg UPC
2013-F	47	1,252,611	26,452
2014-F	48	1,270,836	26,451
2015-F	49	1,290,344	26,451

Pelly Crossing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	28	115,261	4,112
Feb-13	28	88,627	3,158
Mar-13	28	94,708	3,371
Apr-13	28	84,071	2,989
May-13	28	79,504	2,824
Jun-13	28	70,793	2,511
Jul-13	28	68,347	2,422
Aug-13	28	65,521	2,319
Sep-13	28	72,709	2,571
Oct-13	28	78,967	2,789
Nov-13	28	113,977	4,021
Dec-13	28	77,399	2,728
Jan-14	28	116,821	4,112
Feb-14	28	89,836	3,158
Mar-14	28	96,009	3,371
Apr-14	29	85,235	2,989
May-14	29	80,612	2,824
Jun-14	29	71,788	2,511
Jul-14	29	69,315	2,422
Aug-14	29	66,455	2,319
Sep-14	29	73,752	2,571
Oct-14	29	80,108	2,789
Nov-14	29	115,636	4,021
Dec-14	29	78,533	2,728
Jan-15	29	118,624	4,112
Feb-15	29	91,180	3,158
Mar-15	29	97,445	3,371
Apr-15	29	86,508	2,989
May-15	29	81,814	2,824
Jun-15	29	72,857	2,511
Jul-15	29	70,346	2,422
Aug-15	29	67,442	2,319
Sep-15	29	74,847	2,571
Oct-15	29	81,296	2,789
Nov-15	29	117,347	4,021
Dec-15	29	79,694	2,728

	Customers	Energy	Avg UPC
2013-F	28	1,009,884	35,807
2014-F	29	1,024,101	35,806
2015-F	29	1,039,400	35,807

Swift River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	14	23,369	1,667
Feb-13	14	18,025	1,285
Mar-13	14	17,978	1,280
Apr-13	14	15,494	1,102
May-13	14	12,548	891
Jun-13	14	9,285	659
Jul-13	14	8,432	598
Aug-13	14	10,775	763
Sep-13	14	10,732	759
Oct-13	14	13,707	968
Nov-13	14	18,055	1,274
Dec-13	14	18,375	1,295
Jan-14	14	23,682	1,667
Feb-14	14	18,269	1,285
Mar-14	14	18,222	1,280
Apr-14	14	15,706	1,102
May-14	14	12,721	891
Jun-14	14	9,414	659
Jul-14	14	8,550	598
Aug-14	14	10,927	763
Sep-14	14	10,885	759
Oct-14	14	13,903	968
Nov-14	14	18,316	1,274
Dec-14	14	18,641	1,295
Jan-15	14	24,092	1,667
Feb-15	14	18,539	1,285
Mar-15	14	18,492	1,280
Apr-15	14	15,939	1,102
May-15	14	12,909	891
Jun-15	14	9,553	659
Jul-15	15	8,676	598
Aug-15	15	11,088	763
Sep-15	15	11,045	759
Oct-15	15	14,107	968
Nov-15	15	18,584	1,274
Dec-15	15	18,914	1,295

	Customers	Energy	Avg UPC
2013-F	14	176,776	12,537
2014-F	14	179,237	12,536
2015-F	15	181,938	12,538

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Tagish

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	22	25,254	1,148
Feb-08	22	36,477	1,658
Mar-08	22	24,544	1,116
Apr-08	25	26,422	1,057
May-08	20	18,392	920
Jun-08	20	11,850	593
Jul-08	21	13,042	621
Aug-08	22	16,086	731
Sep-08	23	13,294	578
Oct-08	23	19,118	831
Nov-08	23	23,771	1,034
Dec-08	22	23,705	1,078
Jan-09	19	21,201	1,116
Feb-09	23	29,194	1,269
Mar-09	23	23,077	1,003
Apr-09	23	24,157	1,050
May-09	24	19,435	810
Jun-09	22	15,296	695
Jul-09	22	17,049	775
Aug-09	22	16,109	732
Sep-09	22	15,861	721
Oct-09	25	18,091	724
Nov-09	23	20,494	891
Dec-09	24	25,196	1,050
Jan-10	24	31,495	1,312
Feb-10	23	20,170	877
Mar-10	24	28,603	1,192
Apr-10	23	25,020	1,088
May-10	21	19,528	930
Jun-10	23	17,417	757
Jul-10	22	15,016	683
Aug-10	22	13,970	635
Sep-10	19	11,790	621
Oct-10	21	17,435	830
Nov-10	24	21,669	903
Dec-10	23	23,950	1,041
Jan-11	23	30,030	1,306
Feb-11	24	25,614	1,067
Mar-11	24	25,395	1,058
Apr-11	25	31,050	1,242
May-11	26	33,448	1,286
Jun-11	26	18,024	693
Jul-11	23	13,595	591
Aug-11	23	13,512	587
Sep-11	23	12,778	556
Nov-11	25	15,944	638
Nov-11	24	16,744	698
Dec-11	24	26,166	1,090
Jan-12	23	32,209	1,400
Feb-12	23	16,604	722
Mar-12	23	25,466	1,107
Apr-12	19	16,598	874
May-12	23	15,970	694
Jun-12	23	15,204	661
Jul-12	24	18,891	787
Aug-12	24	16,045	669
Sep-12	24	13,882	578
Oct-12	24	15,813	659
Nov-12	24	22,753	948
Dec-12	24	22,475	936

Marsh Lake

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	25	31,098	1,244
Feb-08	25	31,587	1,263
Mar-08	25	28,784	1,151
Apr-08	25	27,459	1,098
May-08	25	19,607	784
Jun-08	23	19,010	827
Jul-08	22	16,652	757
Aug-08	22	20,030	910
Sep-08	24	17,252	719
Oct-08	24	19,263	803
Nov-08	24	28,419	1,184
Dec-08	23	32,895	1,430
Jan-09	24	33,441	1,393
Feb-09	24	27,733	1,156
Mar-09	21	34,092	1,623
Apr-09	23	11,189	486
May-09	24	17,663	736
Jun-09	22	15,389	700
Jul-09	21	16,891	804
Aug-09	21	15,895	757
Sep-09	21	17,977	856
Oct-09	22	17,834	811
Nov-09	24	22,189	925
Dec-09	23	27,937	1,215
Jan-10	24	27,159	1,132
Feb-10	24	21,898	912
Mar-10	24	23,726	989
Apr-10	24	21,966	915
May-10	24	20,304	846
Jun-10	23	15,146	659
Jul-10	23	21,412	931
Aug-10	21	19,031	906
Sep-10	15	9,032	602
Oct-10	21	34,961	1,665
Nov-10	22	28,599	1,300
Dec-10	23	32,912	1,431
Jan-11	23	39,956	1,737
Feb-11	23	28,861	1,255
Mar-11	22	35,924	1,633
Apr-11	20	32,403	1,620
May-11	22	22,563	1,026
Jun-11	22	21,583	981
Jul-11	21	17,059	812
Aug-11	22	18,617	846
Sep-11	21	19,857	946
Nov-11	23	21,173	921
Nov-11	23	27,688	1,204
Dec-11	23	36,375	1,582
Jan-12	23	34,562	1,503
Feb-12	23	36,303	1,578
Mar-12	23	30,477	1,325
Apr-12	23	27,482	1,195
May-12	23	29,931	1,301
Jun-12	23	21,150	920
Jul-12	24	20,492	854
Aug-12	24	23,435	976
Sep-12	24	21,046	877
Oct-12	24	24,365	1,015
Nov-12	25	35,412	1,416
Dec-12	25	39,253	1,570

Deep Creek

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	2	4,794	2,397
Feb-08	2	5,740	2,870
Mar-08	2	3,936	1,968
Apr-08	2	3,899	1,950
May-08	2	3,432	1,716
Jun-08	2	2,148	1,074
Jul-08	2	1,641	821
Aug-08	2	1,278	639
Sep-08	2	1,475	738
Oct-08	2	1,702	851
Nov-08	2	3,834	1,917
Dec-08	2	5,661	2,831
Jan-09	2	6,706	3,353
Feb-09	2	6,706	3,353
Mar-09	2	7,274	3,637
Apr-09	2	5,558	2,779
May-09	2	4,558	2,279
Jun-09	2	3,333	1,667
Jul-09	2	3,144	1,572
Aug-09	2	2,038	1,019
Sep-09	2	2,841	1,421
Oct-09	2	3,052	1,526
Nov-09	2	5,245	2,623
Dec-09	2	4,552	2,276
Jan-10	2	6,121	3,061
Feb-10	2	4,582	2,291
Mar-10	1	679	679
Apr-10	1	670	670
May-10	2	9,364	4,682
Jun-10	2	1,511	756
Jul-10	2	1,598	799
Aug-10	2	1,204	602
Sep-10	2	1,938	969
Oct-10	2	2,135	1,068
Nov-10	2	3,122	1,561
Dec-10	2	3,200	1,600
Jan-11	2	4,248	2,124
Feb-11	2	7,299	3,650
Mar-11	2	5,654	2,827
Apr-11	2	5,959	2,980
May-11	2	2,657	1,329
Jun-11	2	1,945	973
Jul-11	2	1,710	855
Aug-11	2	1,339	670
Sep-11	2	1,751	876
Nov-11	2	2,356	1,178
Nov-11	2	3,144	1,572
Dec-11	2	3,691	1,846
Jan-12	2	6,000	3,000
Feb-12	2	6,066	3,033
Mar-12	2	5,560	2,780
Apr-12	2	5,131	2,566
May-12	2	3,362	1,681
Jun-12	2	3,128	1,564
Jul-12	2	1,665	833
Aug-12	2	1,683	842
Sep-12	2	1,961	981
Oct-12	2	1,803	902
Nov-12	2	2,457	1,229
Dec-12	2	3,829	1,915

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Tagish

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	24	32,181	1,339
Feb-13	24	21,375	889
Mar-13	24	26,944	1,119
Apr-13	24	25,738	1,068
May-13	24	23,412	970
Jun-13	24	17,002	704
Jul-13	24	16,611	687
Aug-13	24	15,259	630
Sep-13	24	14,173	585
Oct-13	24	17,199	709
Nov-13	24	20,631	850
Dec-13	24	24,863	1,023
Jan-14	24	32,602	1,339
Feb-14	24	21,657	889
Mar-14	24	27,302	1,119
Apr-14	24	26,083	1,068
May-14	24	23,727	970
Jun-14	24	17,233	704
Jul-14	25	16,838	687
Aug-14	25	15,469	630
Sep-14	25	14,369	585
Oct-14	25	17,439	709
Nov-14	25	20,922	850
Dec-14	25	25,215	1,023
Jan-15	25	33,102	1,339
Feb-15	25	21,970	889
Mar-15	25	27,697	1,119
Apr-15	25	26,459	1,068
May-15	25	24,069	970
Jun-15	25	17,481	704
Jul-15	25	17,080	687
Aug-15	25	15,692	630
Sep-15	25	14,576	585
Oct-15	25	17,689	709
Nov-15	25	21,221	850
Dec-15	25	25,576	1,023

	Customers	Energy	Avg UPC
2013-F	24	255,389	10,567
2014-F	24	258,857	10,566
2015-F	25	262,612	10,567

Marsh Lake

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	25	36,468	1,457
Feb-13	25	31,279	1,249
Mar-13	25	32,992	1,316
Apr-13	25	31,216	1,243
May-13	25	26,580	1,058
Jun-13	25	21,461	853
Jul-13	25	21,802	866
Aug-13	25	22,932	910
Sep-13	25	20,396	808
Oct-13	25	30,320	1,200
Nov-13	25	33,047	1,307
Dec-13	25	38,670	1,528
Jan-14	25	36,931	1,457
Feb-14	25	31,680	1,249
Mar-14	25	33,418	1,316
Apr-14	25	31,622	1,243
May-14	25	26,928	1,058
Jun-14	25	21,744	853
Jul-14	26	22,092	866
Aug-14	26	23,239	910
Sep-14	26	20,671	808
Oct-14	26	30,732	1,200
Nov-14	26	33,499	1,307
Dec-14	26	39,203	1,528
Jan-15	26	37,481	1,457
Feb-15	26	32,126	1,249
Mar-15	26	33,887	1,316
Apr-15	26	32,066	1,243
May-15	26	27,306	1,058
Jun-15	26	22,048	853
Jul-15	26	22,401	866
Aug-15	26	23,564	910
Sep-15	26	20,960	808
Oct-15	26	31,160	1,200
Nov-15	26	33,965	1,307
Dec-15	26	39,748	1,528

	Customers	Energy	Avg UPC
2013-F	25	347,164	13,792
2014-F	26	351,759	13,792
2015-F	26	356,711	13,792

Deep Creek

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	2	5,462	2,728
Feb-13	2	5,996	2,991
Mar-13	2	4,205	2,095
Apr-13	2	4,162	2,072
May-13	2	5,156	2,564
Jun-13	2	2,209	1,097
Jul-13	2	1,671	829
Aug-13	2	1,421	704
Sep-13	2	1,902	942
Oct-13	2	2,121	1,049
Nov-13	2	2,943	1,454
Dec-13	2	3,621	1,787
Jan-14	2	5,536	2,728
Feb-14	2	6,077	2,991
Mar-14	2	4,262	2,095
Apr-14	2	4,219	2,072
May-14	2	5,227	2,564
Jun-14	2	2,240	1,097
Jul-14	2	1,694	829
Aug-14	2	1,441	704
Sep-14	2	1,929	942
Oct-14	2	2,152	1,049
Nov-14	2	2,986	1,454
Dec-14	2	3,673	1,787
Jan-15	2	5,766	2,728
Feb-15	2	6,167	2,991
Mar-15	2	4,325	2,095
Apr-15	2	4,281	2,072
May-15	2	5,304	2,564
Jun-15	2	2,273	1,097
Jul-15	2	1,719	829
Aug-15	2	1,462	704
Sep-15	2	1,957	942
Oct-15	2	2,183	1,049
Nov-15	2	3,029	1,454
Dec-15	2	3,727	1,787

	Customers	Energy	Avg UPC
2013-F	2	40,869	20,288
2014-F	2	41,435	20,286
2015-F	2	42,194	20,313

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Minto Landing

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-12	2	3,438	1,719
Feb-12	2	3,830	1,915
Mar-12	2	3,613	1,807
Apr-12	2	3,577	1,789
May-12	2	4,618	2,309
Jun-12	2	3,719	1,860
Jul-12	2	3,763	1,882
Aug-12	2	4,660	2,330
Sep-12	2	3,860	1,930
Oct-12	3	3,250	1,083
Nov-12	3	4,665	1,555
Dec-12	3	4,500	1,500

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Minto Landing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	3	5,201	1,719
Feb-13	3	5,842	1,915
Mar-13	3	5,557	1,807
Apr-13	3	5,547	1,789
May-13	3	7,219	2,309
Jun-13	3	5,861	1,860
Jul-13	3	5,978	1,882
Aug-13	3	7,462	2,330
Sep-13	3	6,230	1,930
Oct-13	3	3,524	1,083
Nov-13	3	5,098	1,555
Dec-13	3	4,956	1,500
Jan-14	3	5,728	1,719
Feb-14	3	6,434	1,915
Mar-14	3	6,120	1,807
Apr-14	3	6,110	1,789
May-14	3	7,952	2,309
Jun-14	3	6,456	1,860
Jul-14	4	6,585	1,882
Aug-14	4	8,220	2,330
Sep-14	4	6,863	1,930
Oct-14	4	3,883	1,083
Nov-14	4	5,617	1,555
Dec-14	4	5,460	1,500
Jan-15	4	6,356	1,719
Feb-15	4	7,093	1,915
Mar-15	4	6,742	1,807
Apr-15	4	6,725	1,789
May-15	4	8,746	2,309
Jun-15	4	7,096	1,860
Jul-15	4	7,232	1,882
Aug-15	4	9,022	2,330
Sep-15	4	7,527	1,930
Oct-15	4	4,255	1,083
Nov-15	4	6,152	1,555
Dec-15	4	5,976	1,500

	Customers	Energy	Avg UPC
2013-F	3	68,476	21,638
2014-F	3	75,428	21,637
2015-F	4	82,922	21,641

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Billed to Earned Factor

Communities	Earned	Billed	Billed to Earmed
	2012	2012	Factor
1	2	3	4
Carmacks	2,488	2,445	1.017
Carcross	1,102	1,088	1.013
Haines Junction	3,822	3,768	1.014
Teslin	2,080	2,036	1.021
Upper Liard	300	293	1.024
Destruction Bay	935	919	1.018
Whitehorse	136,170	133,847	1.017
Beaver Creek	1,068	1,054	1.013
Watson Lake	6,713	6,604	1.017
Old Crow	903	887	1.017
Keno City	126	126	1.003
Stewart Crossing	270	264	1.021
Lower Post B.C.	274	268	1.019
Ross River	1,400	1,377	1.017
Pelly Crossing	1,046	1,024	1.021
Swift River	188	184	1.019
Tagish	237	232	1.021
Marsh Lake	351	344	1.020
Deep Creek	43	43	1.002
Minto Landing	48	47	1.018
TOTAL GENERAL SERVICE	159,562	156,851	

The Yukon Electrical Company Limited
Whitehorse Heating Degree Data

Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Commercial Regression Results

Commercial (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77977
R Square	0.60804
Adjusted R Square	0.60584
Standard Error	379.854
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	4E+07	4E+07	276.129	4.8E-38
Residual	178	2.6E+07	144289		
Total	179	6.6E+07			

	Coefficients	*tandard Er*	*t Stat*	*P-value*	*.ower 95%*	*Jpper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	4662.8	55.0	84.8	0.0	4554.3	4771.2	4554.3	4771.2
WH-HDD	1.42567	0.08579	16.61713	0.00000	1.25636	1.59497	1.25636	1.59497

CW-YECL-4

Reference: Other Revenue, Application page 2-9.

In its Application, YECL states:

> Yukon Electrical's other revenues have been included with retail sales revenues as part of the revenue requirement. These amounts are detailed in Schedule 2.2. Reconnect, Joint Use and Services to Outside Parties revenues are forecast to increase in each year of the test period due to inflation. Other Revenues are forecast to decrease starting in 2014 due to a reduction in office rental income.

The City requires information to understand the decrease in 2014 rental income.

Request:

(a) Please fully explain why rental income is forecast to decrease in 2014.

(b) Please fully explain what steps YECL is taking to replace the reduction in rental income.

Response:

(a) The Yukon Government (Economic Development) is choosing to vacate the space they have been leasing on the upper floor of Yukon Electrical's downtown office building, resulting in less rental income. At the time the Application was filed, it was forecast that they would vacate at the end of 2013; however, Yukon Electrical has since learned that they plan to vacate the space at the end of August 2013.

(b) Yukon Electrical is not planning to replace the rental income as the space is needed for Yukon Electrical employees due to the growth in complement over the past few years.

CW-YECL-7

Reference: Operating Costs – DB Pension, Application page 5-3

In its application, YECL provides a table that summarizes DB pension costs. In the table, the costs for DB Special Payments increases from $297,000 in 2011 to $638,000 in 2012. The City requires information to assess the level of pension costs to be recovered from customers.

Request:

(a) Please confirm that YECL employees participate in the same DB pension plan as the employees of YECL's parent, ATCO Electric. If not confirmed, please fully explain and provide all plan documents related to the YECL DB plan.

(b) On line 7 and 8, YECL indicates it has used the same contribution rate for the 2013 test period. Please provide the forecast of DB pension costs included in 2013, 2014, and 2015.

Response:

(a) Not confirmed. Canadian Utilities Ltd. (CU) sponsors two pension plans: Plan 1 (DB and DC) and Plan 2 (DB only). Employees of Yukon Electrical's parent company, ATCO Electric, participate in Plan 1 for both DB and DC. Yukon Electrical employees who are members of the DC plan participate in Plan 1 while Yukon Electrical employees who are members of the DB plan participate in Plan 2 along with employees of other CU subsidiary companies.

The only difference between Plan 1 and Plan 2 is related to the regulation of the two plans. Plan 1 is registered in Alberta and, accordingly, is governed by the Alberta *Employment Pensions Plans Act* and administered and enforced by the Office of the Alberta Superintendent of Pensions in the Employment Pensions Branch in Alberta Treasury Board and Finance. Plan 2 is registered federally and, accordingly, is governed by the *Pensions Benefits Standards Act, 1985* and administered and enforced by the Office of the Superintendent of Financial Institutions ("OSFI"). For purposes of Plan 2, an actuarial report must be prepared annually except for when the solvency ratio is greater than 1.20. Given Plan 2's most recent Actuarial Report as of December 31, 2012 details a solvency ratio

less than 1.20, the next Actuarial Valuation will be required as of December 31, 2013.

(b) The forecast DB pension costs included in 2013, 2014, and 2015 are as follows:

Year	Defined Benefit (annual lump sum)	DB Special Payments (annual lump sum)	Defined Benefit Total
2013	$630	$638	$1,268
2014	$630	$638	$1,268
2015	$630	$638	$1,268

CW-YECL-11

Reference: Cost of Debt, Application, page 8-6

In its Application, YECL has forecast increased cost of new long term debt in 2014 and 2015. The City requires information to assess the forecasts.

Request:

(a) Please fully explain how new long term debt is sourced by YECL? Is new debt mirrored down from an affiliate, such as ATCO Electric, Canadian Utilities, or ATCO? How is the cost of new debt derived?

(b) Please provide the forecast of YECL's parent, ATCO Electric (AE) for long term debt from each of the last three GTAs. (amounts, dates and rates)

(c) Please provide the actual issues of long term debt for the same periods as identified in (b) above. (amounts, dates and rates)

Response:

(a) The gross proceeds of a CU Inc. issue are advanced to Yukon Electrical's parent, ATCO Electric Ltd. The interest rate on the debenture ATCO Electric issues to CU Inc. is the same coupon interest rate as on the CU Inc. debentures issued to the public. ATCO Electric pays CU Inc. its pro-rata share of CU Inc.'s issue costs at the time the debenture is issued. ATCO Electric then amortizes the issue costs on a monthly basis over the term of the debenture.

ATCO Electric, in turn, advances funds to Yukon Electrical on the same understanding – i.e., that Yukon Electrical will reimburse ATCO Electric for its pro-rata share of the issue costs incurred by ATCO Electric. In the case of Yukon Electrical, this monthly amortization is considered to be administratively inefficient, given the relatively small sums involved. It is considered to be more efficient for the issue costs to be "rolled into" the interest rate and be paid to ATCO Electric over the life of each debenture. Accordingly, the coupon interest rate on the Yukon Electrical debenture is set equal to the embedded rate (i.e. the coupon interest rate on the CU Inc. debentures issued to the public interest rate plus an amount to cover issue costs).

Yukon Electrical has forecast the amount to be added to the coupon rate for issue costs to be 5 basis points for 2013-2015. This is the same amount used in previously approved applications and is based on an estimate of the costs that CU Inc. will incur when it issues debentures to the public.

(b) In the following table, please find ATCO Electric's forecast long term debt issuance dates and rates from each of its last three GTAs. The forecast amount of debt to be issued by ATCO Electric is not relevant to Yukon Electrical's Application as the two companies have materially different capital programs which drive materially different financing requirements.

Year	Issue Date	Issue Rate
2007	2007-06-30	5.20%
2008	2008-06-30	5.20%
2009	2009-06-30	6.65%
2010	2010-06-30	6.65%
2011	2011-06-30	5.75%
2012	2012-06-30	6.35%

(c) In the following table, please find ATCO Electric's actual long term debt issuance dates and rates for the same periods identified in part (b). The actual amount of debt issued by ATCO Electric is not relevant to Yukon Electrical's Application as the two companies have materially different capital programs which drive materially different financing requirements.

Year	Issue Date	Issue Rate
2007	2007-11-01	5.556%
2008	2008-05-26	5.563%
	2008-05-26	5.580%
2009	2009-03-06	6.215%
	2009-03-07	6.500%
2010	2010-11-10	4.947%
2011	2011-10-24	4.543%
	2011-10-24	4.593%
2012	2012-09-10	3.805%
	2012-09-10	3.825%
	2012-11-14	3.857%

In comparing forecast rates from part (b) above to actual rates in this part (c), there are instances where forecast rates were lower than actuals and others where they were higher than actuals. The reason actual rates were lower than forecast for the 2010 to 2012 period was the impact of central bank stimulus activity since the 2008/2009 global financial crisis. As a result of these activities and general market uncertainty, Government of Canada Bond Rates unexpectedly dropped to historic lows. The forecasts used for the 2010 to 2012 period did not reflect this unexpected move in Government of Canada Bond Rates. The external forecasts relied upon for 2013 to 2015 period take into consideration central bank stimulus activities and expectations for how those activities will gradually recede over time, which will result in interest rates increasing to more “normal” levels.

CW-YECL-27

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 30 and Yukon Five Year Demand Side Management Plan

YECL provides a joint Demand Side Management (DSM) report. The City requires information to assess the project.

Request:

(a) On page 24 and 25 of the Yukon Five Year Demand Side Management Plan, the report discusses implementation. There does not appear to be an analysis of the Lifecycle costs of program. Please provide an analysis of the cost of the program over the life of the program, identifying:

(i) Yukon Electrical program delivery costs for each year.

(ii) projected human resource costs related, and costs allocated to YECL for each year.

(iii) projected marketing and communications costs that occur outside of the Demand Side Management Program Portfolio costs, and costs allocated to YECL for each year.

(iv) projected agreed upon pilot projects (LED street lights), and costs allocated to YECL for each year.

(v) Costs beyond the in Charge commitments:

- Internal DSM projects
- Administrative costs
- Staff training and development
- YECL industrial customer DSM programs
- YECL office costs
- Additional staff costs

(vi) Please separate operating and capital costs.

(vii) Please reconcile the costs provided in response to (i) – (iv) above to the costs included in this GRA.

(b) The City is interested in understanding the measurement of results and achievement of goals and benefits. On page 25 of the Yukon Five Year Demand Side Management Plan, it states that program level evaluation, measurement and verification (EM&V) is available in the Joint Utility EM&V Plan (2013). Please indicate if and where this report is included in this application. Specifically please identify where details about EM&V are provided. If the Joint Utility EM&V Plan (2013) is not included in this filing, please provide the report.

(c) Please provide the benefit, in terms of reduced capital or operating costs, of achieving the 8.5 GWh target of the program.

(d) Please fully describe the process for the review and approval of budgets and actual expenditures of the DSM program.

Response:

(a) The joint DSM plan is five years in duration and is not analyzed as a whole on a life cycle basis. Lifecycle analysis was completed for each of the program technologies and was evaluated against the industry standard four cost effectiveness tests. Please refer to the *DSM Program Incentive Justification Levels*, provided in YUB-YECL-27 Attachment 1, for the test evaluations of each technology measure.

(i) Yukon Electrical annual DSM costs are listed in Business Case #30.

2011 - $204,000
2012 - $143,000
2013 - $135,000
2014 - $522,000
2015 - $730,000

(ii) Please refer to the *YECL-DSM Costs 2011-2015* spreadsheet, provided in YUB-YECL-24(b) Attachment 1, for a detailed cost breakdown.

(iii) There are no additional marketing and communication costs related to DSM outside of the program portfolio costs for Yukon Electrical.

(iv) As of the date of this submission the only joint project undertaken is the LED street light pilot study, currently underway with the report expected to be delivered by the end of 2013. The cost to Yukon Electrical related to the LED street light testing project was $2,000 in 2012 and is forecast to be $1,200 in 2013.

(v)

- Internal DSM projects – Yukon Electrical is not applying for any costs related to internal DSM.
- Administrative costs – Yukon Electrical is not applying for any additional costs related to Administrative costs.
- Staff training and development – In 2014, Yukon Electrical is applying for $19,000 for staff training and development as there is currently no internal expertise on DSM. In 2015, Yukon Electrical is applying for $17,000 for staff training and development to provide on-going DSM development for the projected DSM staff.
- Yukon Electrical industrial customer DSM programs – Yukon Electrical is not applying for any DSM costs associated to industrial customers.
- Yukon Electrical office costs – Yukon Electrical is not applying for any additional costs associated with office costs.
- Additional staff costs – Yukon Electrical is applying for additional staff costs of $47,400 in 2013, $91,000 in 2014 and $93,000 in 2015 related to the DSM Coordinator position.

(vi) It is Yukon Electrical's intention to capitalize all costs associated with the DSM program. However, in preparing the responses to Information Requests, it was discovered that some costs had inadvertently been included in both Operations and Maintenance expenses and Capital. These amounts total $88,000 for 2013, $90,000 for 2014 and $92,000

for 2015. This duplication will be rectified by the removal of costs from O&M and this will be corrected and submitted as part of Yukon Electrical's compliance filing.

(vii) There is an immaterial variance in 2012 of $1,800 between the cost breakdown provided in YUB-YECL-24(b) Attachment 1 and the amount included in the Application. For all other years, the costs as per the breakdown agree to the amount as filed.

(b) Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

(c) An analysis of the fuel and O&M costs and the additional diesel capacity (capital) costs with and without a DSM program which saved 8.5 GWh can be seen in figures 4.1 and 4.2, respectively, of the *Yukon Energy 20 Year Resource Plan: 2011-2020*. In the absence of a completed DSM Program, the resource plan examined this scenario for the Base Case in 2015. Fuel and O&M savings for this scenario were estimated at $2.6M and diesel capacity additional savings for this scenario were estimated at $4.7M. The cost of conserved energy of the measures was compared against a $0.21 per kilowatt hour cost which represents a blended avoided cost of supply.

(d) Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL 26(a) Attachment 1, and the *DSM Program Implementation Plan*, provided as CW-YECL-27(d) Attachment 1.



Demand-Side Management (DSM) Program Portfolio for the Yukon

FINAL
PROGRAM IMPLEMENTATION PLAN

Date: May 30, 2013

Submitted to:
Yukon Energy Corporation
Yukon Electrical Company Limited

Submitted by:
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Executive Summary

This report presents the program implementation plan (PIP) for the Yukon demand-side management (DSM) program portfolio. It represents the final step in the YEC and YECL's DSM planning process, which began with the completion of the study entitled *Conservation and Demand Management Potential for the Yukon*.

The PIP defines the full scope of operational and transactional infrastructure that is required to operate the DSM program portfolio. As such, the PIP presents the performance indicators, the targets, the deliverables, the human resource requirements, the roles and responsibilities, and the budgets required to operate the DSM Program Portfolio over a full five year cycle. Particular emphasis is given to the Program Portfolio's operational requirements in its first year of activity.

The Program Implementation Plan, which is an extension of the program design document, *Demand-Side Management Program Portfolio for the Yukon*, is accompanied by an evaluation, measurement and verification (EM&V) plan.

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1. Introduction

Yukon residents rely on electricity not only to live meaningful, healthy lives but also to support and strengthen the economy. Given the concerns over environmental implications including climate change, and the limited generating capacity in the Yukon, there is growing interest not only in how electricity is generated, transmitted and distributed but also how efficiently it is used at the customer's end. In the Yukon, as well as in a growing number of North American jurisdictions, how electricity is generated and used is being closely analyzed to find innovative ways of meeting individual and corporate energy service needs while minimizing pollution and the creation of greenhouse gases.

In response to these conditions, the Yukon Energy Corporation (YEC), Yukon Electrical Company Limited (YECL) and the Yukon Government collaboratively commissioned a comprehensive study of the opportunities for electricity demand-side management (DSM) within the Yukon. That study, entitled *Conservation and Demand Management Potential for the Yukon 2011*, was completed in January 2012 and revealed a significant cost-effective potential for electricity DSM in the Yukon. Based on those findings, the YEC and YECL developed a suite of residential and commercial sector program offerings that will enhance the Yukon's electricity DSM program portfolio and provide incremental annual electricity savings of 9.3 GWh/yr by the fifth year of the program. The results of the development work are presented in a report, entitled *Demand-Side Management Program Portfolio for the Yukon*, which was completed in September 2012.

This report, which is the final step in the DSM planning process, provides a program implementation plan (PIP) suitable for submission to the Yukon Utilities Board, together with an evaluation, monitoring and verification (EM&V) plan.

1.1 The Planning Process

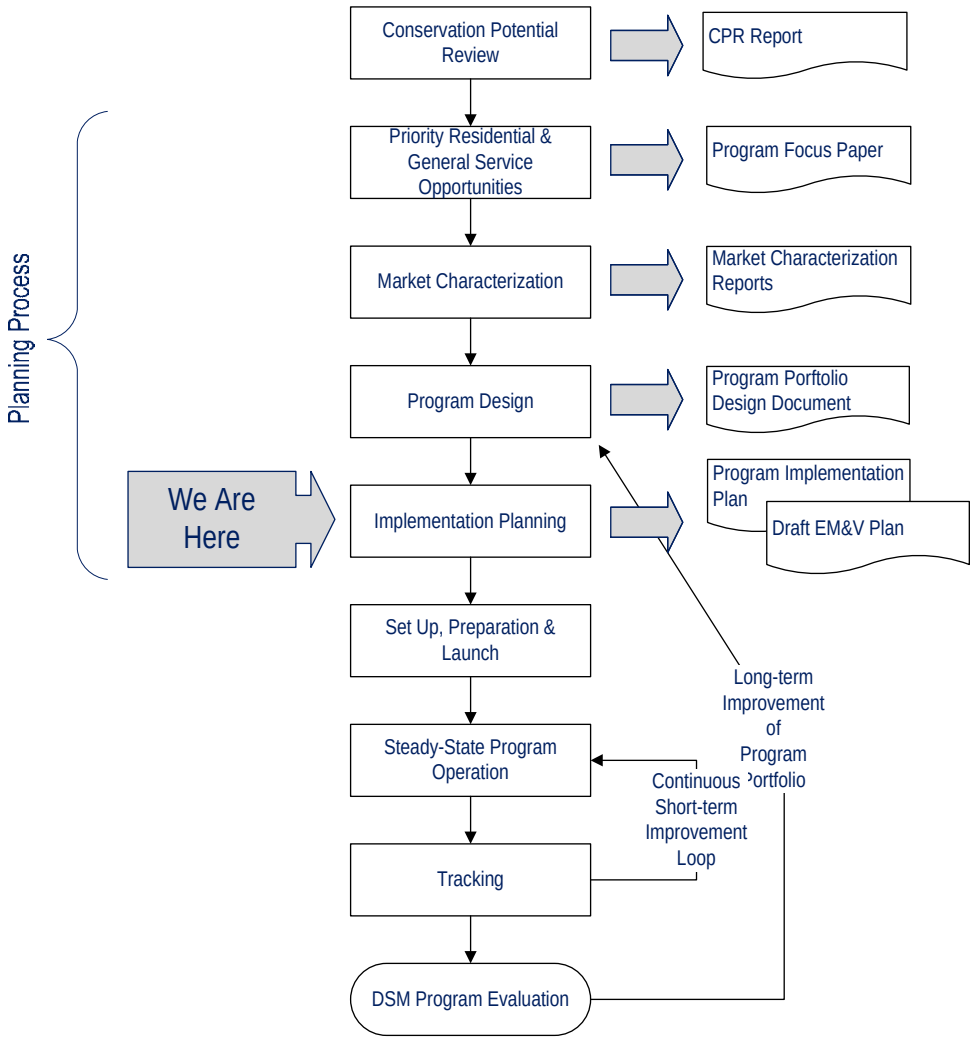
The DSM Program Implementation Plan presented in this report is the product of a multi-step process, which was designed to gather and analyze the data necessary to determine optimum program structure and cost-effective design.

The planning process was organized into 4 major steps:

- Step 1: Priority Residential and General Service Opportunities
- Step 2: Market Characterization
- Step 3: Program Design
- Step 4: Program Implementation Planning

Exhibit 1 provides a graphic of the steps involved in the planning process and its relationship to the Yukon Conservation Potential Review (CPR) results.

Exhibit 1: Program Planning Process



A brief description of the main steps shown in Exhibit 1 is provided below. More detailed information is provided in the appendices that accompany this report.

Step 1: Priority Residential and General Service Opportunities

This first step in the planning process was to determine which of the several hundred technologies and measures analyzed in the 2011 Yukon CPR should provide the initial program focus.

As a starting point the extensive listing of individual measures and technologies contained in the CPR results were screened. The priority opportunities were bundled into potential program elements and each was subjected to further detailed market research.

Step 2: Market Characterization

This market research step provided the program design team with a comprehensive understanding of the key factors influencing market penetration of the electricity efficiency technologies and measures; these findings informed the design of the specific programs and activities.

The detailed market research employed a variety of data collection methods and included a broad range of Yukon personnel involved in the supply, service, purchase and use of electricity efficiency technologies and measures. The research focused on developing clarity around four key areas, namely: market barriers, market structure, market actors, and baseline conditions.

Step 3: Program Design

The knowledge gained from the above market research provided key design inputs into the DSM program portfolio. For example, the understanding of market barriers was critical to the selection of appropriate activities or program offerings; similarly, a thorough knowledge of the market structure and major actors within the supply chain provided insight into potential partners and marketing strategies that will be most effective.

The collection of data on baseline conditions provided important inputs to the cost effectiveness testing that is critical to the program design process, and to the eventual program evaluation requirements.

Step 4: Program Implementation Planning

The last step in the planning process, which is the focus of this report, is to determine the full breadth of operational requirements to create the designed DSM portfolio's transactional and operational infrastructure, and to operate the portfolio in its first year.

This report also includes the performance indicators, the targets, the deliverables, the human resource requirements, the roles and responsibilities, and the budgets required to operate the DSM program over its full five year cycle.

1.2 Report Presentation

The remainder of this report is organized and presented in the following sections:

- Section 2 introduces the implementation approach, work package structure and schedule.
- Section 3 describes the resources required to operate the DSM portfolio.
- Section 4 defines the proposed management procedures.
- Section 5 provides an integrated communication plan for the General Service and Residential programs.
- Section 6 provides a summary of the operational budget, and a description of the main cash flows between the utilities and the ratepayers, and between utilities.

2. Work Plan

Section 2 presents an overview of the proposed four-phase approach to program implementation, an outline of the recommended work package structure (WPS), and a preliminary 'high-level" schedule.

2.1 General Approach

The goal is to launch most of the program elements concurrently during the first three quarters of program operation and to have the program elements reach steady-state operation before the end of the first year of operation.

A four-phase approach is envisioned for the launch of the program portfolio.

- Phase 1: Mobilization of the Implementation Team
- Phase 2: Preparation and Launch
- Phase 3: Training and Transition to Regular Operation
- Phase 4: Steady-State Program Operation

The YEC Energy Conservation (EC) Manager and the YECL DSM Supervisor will lead the launch of all of the program elements. The YEC Energy Conservation Manager will be responsible for finalizing the detailed work plan, and for updating the work plan on a sliding quarterly basis.

It is envisioned that during Phases 1 and 2, the Core Team (about four people) will be supplemented by external DSM experts (Launch Contractor), as required.

Further discussion of each step is provided below.

Phase 1: Mobilization of the Team

Highlights of Phase 1:

- The Utilities will select a Launch Contractor and mobilize the Core Team under the lead of the YEC Energy Conservation Manager (in collaboration with the YECL DSM Supervisor). The selected Launch Contractor will be responsible for supporting, engaging and training the local staff, and establishing many of the key program procedures and tools that will be essential to successful program operation in the four years that will follow. Further detail on team and member qualifications is provided in Section 3.1.
- The detailed short-term work plan that will be provided as part of this Implementation Plan will be the starting point for the Core Team and Launch Contractor; however, it is expected that the YEC Energy Conservation Manager will adapt the detailed work plan to his/her own management preferences and style.

Phase 2: Preparation and Launch

The team will execute the short-term work plan. This includes:

- Developing and initiating the operation of the DSM office, including:
    - The transactional infrastructure (e.g. front-end forms, agreements, notice & letter templates); and

  - The operational infrastructure (e.g. back-end forms and reports, procedures and tracking system).[1]

- Executing the engagement and communication strategy, including:
  - The launch tactics (e.g. new web page content, brochures, press release, and perhaps a press conference), and
  - The establishment of the engagement & communication coordination function(s) (e.g. monitoring and reacting to program uptake; planning, developing and delivering new communication and education tactics as needed; maintenance of the webpage and program documentation; and surveillance of public-relations opportunities).

The Utilities will go public with the program offerings during Phase 2. The launch tactics will be delivered in close collaboration.

Phase 3: Training and Transition to Regular Operation

As the first program transactions are processed, the team will undoubtedly identify less-than-optimal transactional materials and procedures. Necessary corrections and streamlining of the transactional and operational infrastructure will be applied, as applicable.

The Launch Contractor will provide training on DSM planning, operations and customer engagement through a mentor/protégé working relationship with the local staff and their involvement in the preparation and launch tasks. The Launch Contractor will use a wide array of training vehicles including: lectures, webinars, readings, quality assurance, and the development of job aids like operation manuals and decision support spreadsheets.

The Launch Contractor will ensure a smooth transition of all the tasks and responsibilities to the core team and then phase out of program operation.

Phase 4: Steady-State Program Operation

The Core Team will:

- Operate the DSM back-office.
- Plan and execute engagement, education and communication tactics.
- Conduct some site visits and verifications.
- Monitor program uptake and other key performance indicators.
- Review program results, adapt, plan and lay out the budget for next year.
- Seek continuous improvement by monitoring suggestions from the operation personnel and market actors, and by planning and implementing the applicable changes.
- Manage the evaluation, measurement and verification (EM&V) contractor; provide the program data as requested by the contractors; and provide feedback on the EM&V draft reports.
- Manage other contractors that may be involved in the operation of the program.

[1] Establishing clear procedures and standards with respect to permissions and privacy will be a critical element of this step.

2.2 Work Package Structure

The work package structure (WPS) will be used as the budget breakdown structure (BBS), which will also be used for time and expense tracking purposes and managerial accounting. It should be noted that the WPS/BBS is subject to change over the course of the 5-year DSM portfolio operation as program elements are likely to evolve over the period in response to changing market conditions. The proposed WPS for the Residential and General Service DSM programs is outlined below in Exhibit 2.

Exhibit 2: Proposed Work Package Structure for the Yukon DSM Programs

WP1 General Service Program

- WP1.1 Program Management
  - WP1.1.1 General Management Time & Materials (YEC)
  - WP1.1.2 Tracking System Development & Maintenance (YEC)
- WP1.2 Engagement, Training and Communication
  - WP1.2.1 Direct Customer Engagement (YECL)
  - WP1.2.2 Training and Indirect Communications (YEC)
- WP1.3 Lighting Redesign and Equipment Incentive
  - WP1.3.1 Time & Materials (YEC)
  - WP1.3.2 Incentive Disbursement (YEC)
- WP1.4 Energy Star Computer Incentive *(ibid)*
- WP1.5 High-Efficiency Refrigeration *(ibid)*
- WP1.6 New Construction Incentive *(ibid)*

WP2 Residential Program

- WP2.1 Program Management *(Same sub-WPS as for WP1.1)*
- WP2.2 Engagement, Education and Communication *(Same sub-WPS as for WP1.2)*
- WP2.3 LED Lighting and Automotive Heater Timer Rebates *(Same WPS as for WP1.3)*
- WP2.4 Promotion of Low-Cost Energy-Efficient Products *(ibid)*
- WP2.5 Cold-Climate Heat Pump and Ground-Source Heat Pump System Initiative *(ibid)*

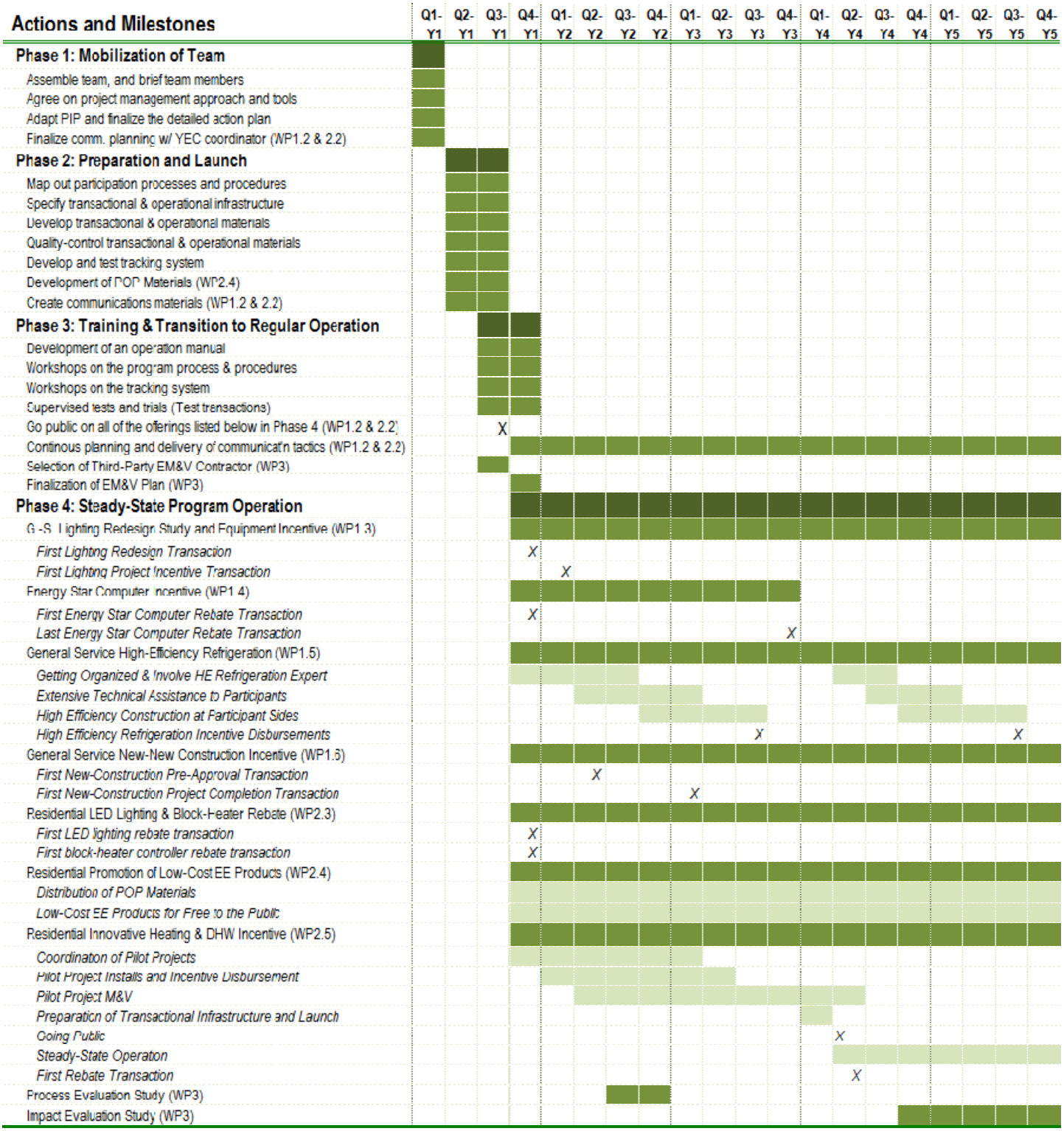
WP3 Evaluation, Measurement and Verification

(To be determined once the Evaluation, Measurement and Verification Plan is finalized with the EM&V Contractor)

2.3 High-Level 5-Year Schedule

Exhibit 3 shows the proposed schedule for implementing the program. A detailed action plan for Year 1 is presented in Appendix A.

Exhibit 3: High-Level Gantt Chart of the Program Portfolio Implementation



3. Resource Plan

Section 3 defines the resources required to operate the program (human resources, contractors and information technologies) and provides general procurement guidelines.

3.1 Human Resources Plan

Based on the approach described in Section 2, approximately four full-time equivalent workers (FTE) will be required for the management and operation of the General Service and Residential Programs. This core program operation team (Core Team) of four workers will be employed directly by the Utilities, jointly funded by the Utilities and under the brand inCharge (the joint utility brand for DSM. Contractors will be added and corporate staff will support the team on an as-needed basis.

The FTEs of the Core Team will likely be formed as follows:

- Two will be YEC employees. Their primary responsibility areas will be program management, in-direct communications, tracking, and evaluation, measurement and verification.[2]
- Two will be YECL employees[3]. Their primary responsibility area will be direct customer engagement and back office work.

The Core Team will be based in the Yukon in the Utilities' existing office space. Candidates for the Core Team include existing and new employees that will work on the General Service and/or the Residential Program. It is expected that core team staff will be added gradually over the first four quarters as activities ramp up.

The core program team will also need the assistance of external DSM experts (contractors). These external DSM experts will:

- Assist with the launch of the program portfolio until fully operational.
- Establish the processes and procedures and provide training to the Core Team, as needed.
- Have an exit strategy. Minimal involvement of external experts is expected beyond the third phase, aside from their involvement in EM&V, and in the High-Efficiency Refrigeration program element.

New hires, if required, do not need to be DSM program experts as they can be trained and assisted by DSM experts. They will be recruited through the standard human resource procedures of the Utilities based on standard job descriptions for similar work and experience-level requirements.

The expertise and external human resource requirements are bundled into work packages as presented in Section 3.2 – Procurement Plan.

[2] Further details on roles and responsibilities are to be laid out in Section 4.1.
[3] The costs associated with the YECL DSM Supervisor (Coordinator) are accounted for in YECL costs outside of the Marbek Program Design

3.2 Procurement Plan

Exhibit 4 provides a preliminary draft of the procurement plan. Each entry in the table is to become a contract with a service supplier. These are service contracts only. No equipment will be purchased to deliver the program. The assumption was made that office space, office IT infrastructure and office stationery are to be provided by the suppliers. The role and responsibilities of inCharge personnel mentioned in Exhibit 4 are to be laid out in Section 4.1 and 4.2.

Exhibit 4: Preliminary Procurement Plan

#	Contract Title	Amount (Approx.)	Start/End	Contract Awarded	Notes on the Scope of Work	Comments on Prospective Suppliers
1	DSM Portfolio Preparation & Launch Support a.k.a. "Launch Contract"	Between $230,000 and $290,000	Start: Y1-Q1 End: Y2-Q1	Before Y1-Q1	Support the YEC EC Manager and YECL DSM Supervisor with project management and coordination; Plan, design, and create transactional and operational infrastructure for all program elements. Finalize prescriptive incentive levels, eligible products and specifications, and customer incentive levels. Design and create DSM tracking system, set-up and start the operation of the tracking system. Support the YEC EC Manager, YECL DSM Supervisor and Communication Contractors with the finalization of the communication plan, finalization of the list of tactics and schedule, and with the production of communication content. Supervise the testing and tuning of the transactional infrastructure, operational infrastructure and tracking system based on the first DSM transactions. Training inCharge core staff in DSM launch and planning though multiple means: lectures, webinars, readings, ride alongs, job aids, development of operation manuals, mentoring, learning-by-doing, delegation of tasks, and quality control. Support and training of the YECL program Back-Office Coordinator on operational procedures and tracking, and YECL Customer Engagement Officer on engagement approaches and tracking, transfer responsibilities and send off. Support YEC with "special" program elements: General Service HE Refrigeration, Residential Innovative Heating System Program element, and Residential low-cost energy efficiency product element.	Consulting firm with DSM expertise, and DSM program implementation experience. Some energy engineering qualifications required.
2	Multiple contracts / Expert	Between $200,000 and $250,000	Multiple contracts over the course of the	Depending on the contract	Provide technical assistance to participants as part of the General Service HE Refrigeration program element. Deliver training course to Yukon equipment or service providers (if any, when	Highly qualified energy engineer(s); most likely freelancers. Consultant with specific expertise as

#	Contract Title	Amount (Approx.)	Start/End	Contract Awarded	Notes on the Scope of Work	Comments on Prospective Suppliers
	consultants	in total	following period: Start: Y2-Q1 End: Y5-Q4		needed). Hands-on training to Yukon equipment or service providers (if any, when needed). If required, support EM&V contractor with updates to prescriptive incentive lists. Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).	needed.
3	Yukon DSM Portfolio Evaluation, Measurement and Verification a.k.a. EM&V Contract	Between $360,000 and $440,000	Start: Y2-Q1 End: Y5-Q4	Y1-Q4	Finalize the evaluation, measurement and verification plan. As part of the above, review the tracking system and procedures, and recommend changes to maximize the value of EM&V. As part of the above, establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, etc. As part of the above, collect some additional market baseline information if and as needed. Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6 quarters after the launch). As part of the above, do some quality control/quality assurance of the program impacts as computed by the tracking system. Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.	Consulting firm with experience in DSM program evaluation, measurement and verification. Program-level evaluation experience is a minimal requirement. Project-level measurement and verification experience is beneficial but not essential.

3.3 Program Tracking Database

The central component of a tracking system is the database. The other key components are internal forms and procedures to input data, data quality control and assurance measures, and reports.

Exhibit 7 identifies three types of DSM program tracking databases, together with a summary of their strengths and weaknesses.

Exhibit 7: Three Types of DSM Program Tracking Databases

#	Type of Program Tracking Database	Strengths	Weaknesses
1	Database-like Spreadsheets	Very inexpensive (a few thousand dollars). Easy to find people to change and adapt the database – people with qualifications in Excel are relatively easy to find. Can be shared on file-sharing sites.	Limited inputting and query/reporting features. Spreadsheets are not organized as a database by default – making the file a "database-like set of spreadsheets" requires special care. Technical limitations in terms of: number of sites the database will be accessible from, amount of data in the same file, tendency for MS-Excel to crash. Versioning and preventing multiple copies of the database to circulate will be a challenge. It is challenging to record changes of the entries (for example: program participation status), and report on the history of each entry later.
2	Simple Database Built on a Database Platform (e.g. Access, MySQL) – from scratch or by modifying an existing program tracking database	None of the disadvantages above. Less costly than the option below. The system remains relatively simple and thus can be modified more easily. Can be shared on file-sharing sites, such as Sharepoint.	More costly than Database-Like Spreadsheets (a few tens of thousand dollars).
3	Sophisticated customized Customer Relationship Management software	Multiple advanced features, Integration with other database used by the utility.	Very costly (millions of dollars). Difficult to service – requires doing business with the initial developer.

The use of a database-like spreadsheet tracking system is recommended, as it best matches the Utilities' needs. It is assumed that the team will lead the development of the tracking system with the support of the Launch Contractor, as required, during the startup phase. The team will likely use commercially-available spreadsheet software like Microsoft Excel. The Launch Contractor will provide support to the Utilities to create the blueprint of the database and the blueprints of the procedures surrounding the use of the database.

The workbook will be built like a relational database to ensure that: data are well organized; data quality control/quality assurance and clean-up are easy to perform; and, data analysis and reporting are fully supported.

To perform like a relational database the workbooks will include the following characteristics:

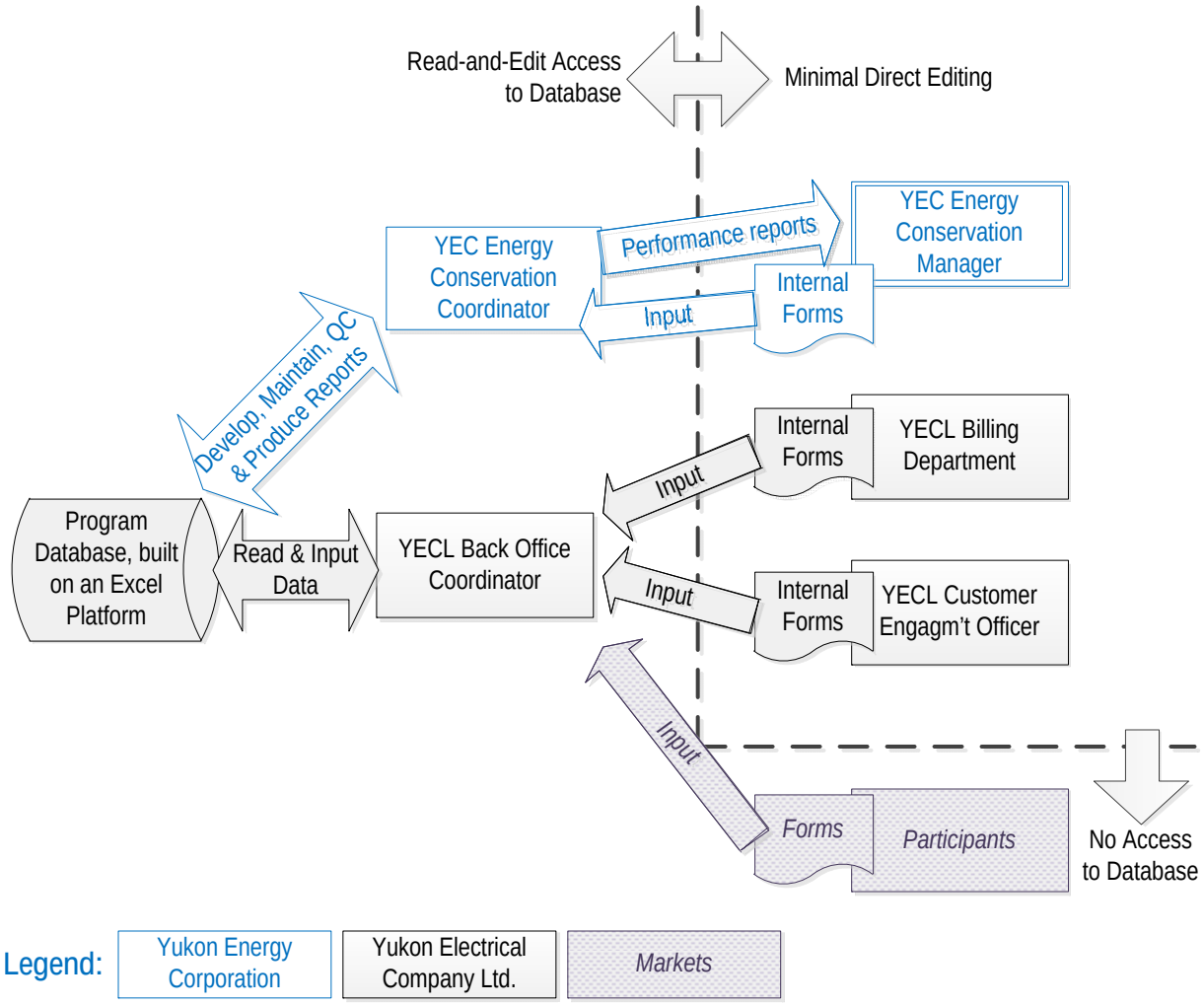
- Be made of a set interlocking "data storage" tables (worksheets).

- Keep the output sheets, charts and reports, and data storage tables in separated tabs.
- Present each entry in its own row in the data-storage tables.
- Identify each entry with its own unique identification number.

The proposed data flow through the program tracking database is presented in Exhibit 8. As illustrated, the YECL Back-Office Coordinator and the YEC Energy Conservation Coordinator will be the database custodians. It is recommended that all other YEC and YECL personnel perform minimal direct editing in the database, as illustrated in Exhibit 5.

Options for other utility staff to feed information into the database include: sending an email to YECL Back-Office Coordinator; populating and sending an internal form; or directly forwarding the paperwork sent in by participants. The YECL Back-Office Coordinator will receive the data, validate the data, and then enter it into the data tables. The YEC Energy Conservation Coordinator will be responsible for reporting, directing traffic, and quality controls.

Exhibit 5: Data Flow through the Program Tracking Database



The program tracking database will be the responsibility of the YEC Energy Conservation Manager with access granted to employees from both companies.

At the end of the program implementation stage, there are two documents that, when combined, will be used for the development of the tracking database:

- The PIP: This section and Section 4.7.
- The list of researchable issues as part of the EM&V Plan.

During startup, the team will initiate the database development with the drafting of the following charts, later to be used as blueprints for the system.

- The detailed program participation process diagram.
- The tracking database architecture chart.

4. Management Plan

The management plan presents the recommended procedures required to balance the requirement to operate and adapt the DSM portfolio to changing market conditions and the requirement for the oversight entity (either or both the YUB and the YEC/YECL Management Committee) to review how ratepayer monies are spent.

The management plan is organized and presented in the following sections:

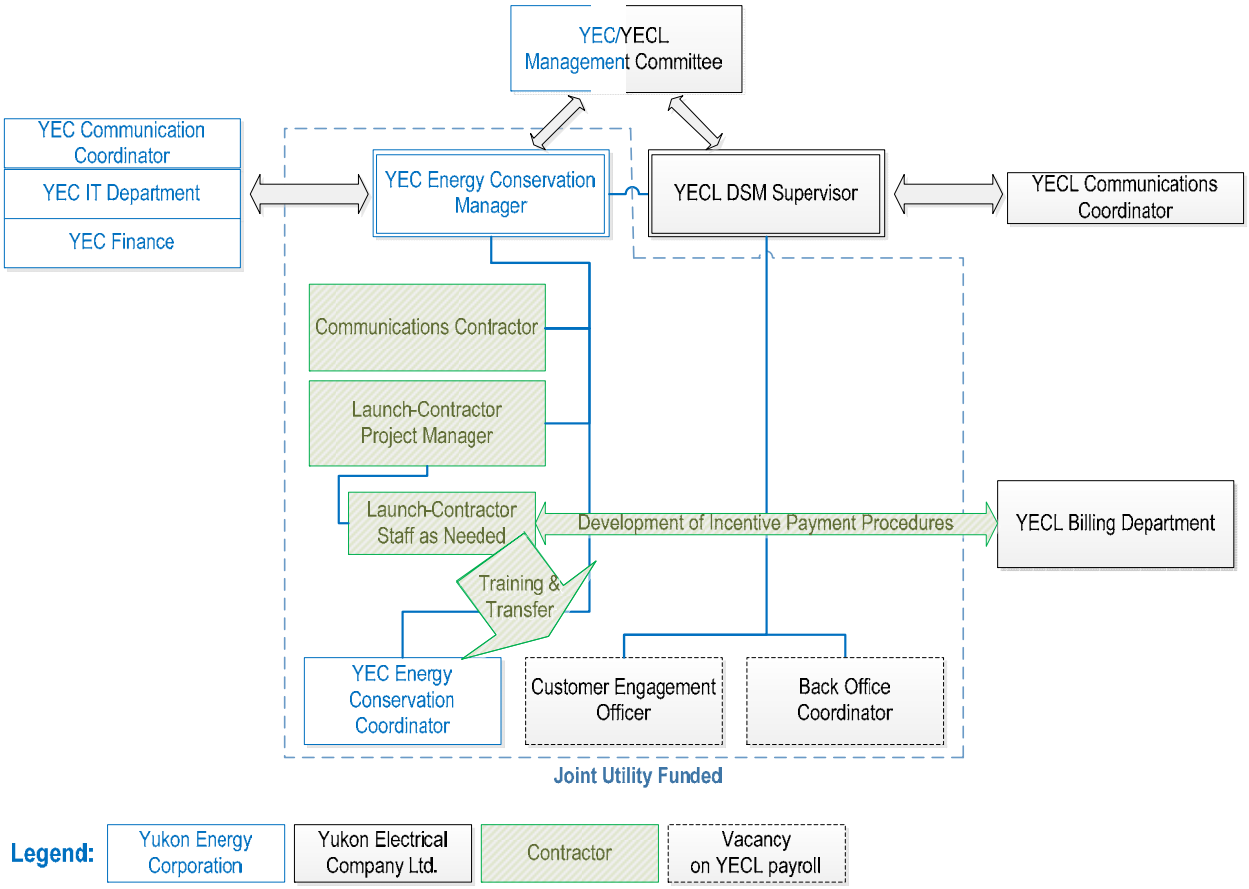
- Roles and responsibilities during program start up[4]
- Roles and responsibilities during full program operation
- Goals and performance tracking
- Operational reporting and planning
- Contingency plan
- Standards, policies and guidelines
- Information flow mapping

[4] Given the shift in roles and activities that occurs between program startup and full operation, this PIP presents the roles and responsibilities separately.

4.1 Roles and Responsibilities during Program Startup

Exhibit 6 presents the organization chart for Phases 1, 2 and 3 of the DSM portfolio delivery (mobilization of the team, preparation, launch, and transition to regular operation). The preliminary roles and responsibilities of each party are subject to change based on YEC or YECL internal organization, changing market conditions, and early program results. An explanatory note is presented in tabular format following the chart.

Exhibit 6: Organization Chart for the Launch of the DSM Portfolio



Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Coordinate with YECL DSM Supervisor to ensure business needs are met. • Procurement of the services of a Launch Contractor and Communications Contractor. • Coordination between the positions or resources shown in Exhibit 6. • Update/finalization of the detailed work plan, project activity monitoring, and then of the update of the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the contractors' deliverables. • Update/finalization of the communication plan.

Position	Payroll	Role/Responsibility during DSM Portfolio Launch
		• Control and approval of the engagement plan developed by the direct Customer Engagement Officer. • Jointly responsible for the public relations activities on behalf of inCharge with YECL DSM Supervisor. • Jointly responsible for development of communications content (examples: website content, print-media content and social media if any) with YECL DSM Supervisor and supported by the YEC and YECL communications coordinators.
Launch Contractor	Contractor for YEC	• Support YEC Energy Conservation Manager and YECL DSM Supervisor on project management. • Support YEC Energy Conservation Manager, YECL DSM Supervisor and communication contractors in laying out the program offerings, incentive levels and eligibility criteria to target markets in communication materials. • Finalize the prescriptive and custom incentive levels and eligibility criteria. • Update of the DSM cost-effectiveness modeling. • Finalize or develop the detailed blueprints and specs of the program element processes. • Development of materials that form the transactional and operational infrastructure. • Create the blueprint for the database and the blueprints of the procedures surrounding the use of the database. • Train core utility staff in DSM launch and planning though multiple means: lectures, webinars, readings, ride alongs, job aids, development of operation manuals, mentoring, learning-by-doing, delegation of tasks, and quality control. • Train core utility staff in application processing, and use of the tracking system. • Testing/Processing the first transactions. • Identification of the low-cost products that are to be promoted under the inCharge brand, and support to the YEC Energy Conservation Manager, YECL DSM Supervisor and communications coordinator in the creation of POP material (wrt: Residential Promotion of Low-Cost Energy-Efficient Products program element). • Advisory for the Customer Engagement Officer, the YEC Energy Conservation Manager and the YECL DSM Supervisor to find heating pilot-project sites, and recruit trusted HVAC contractors (wrt: residential innovative heating program element). • Advisory for the YEC Energy Conservation Manager to find a trusted high-efficiency refrigeration contractor and for the engagement officer to start engaging with the prospective High-Efficiency Refrigeration program participants (wrt the General Service HE Refrigeration program element). • Advise the YEC Energy Conservation Manager and YECL DSM Supervisor in the selection of an EM&V contractor.

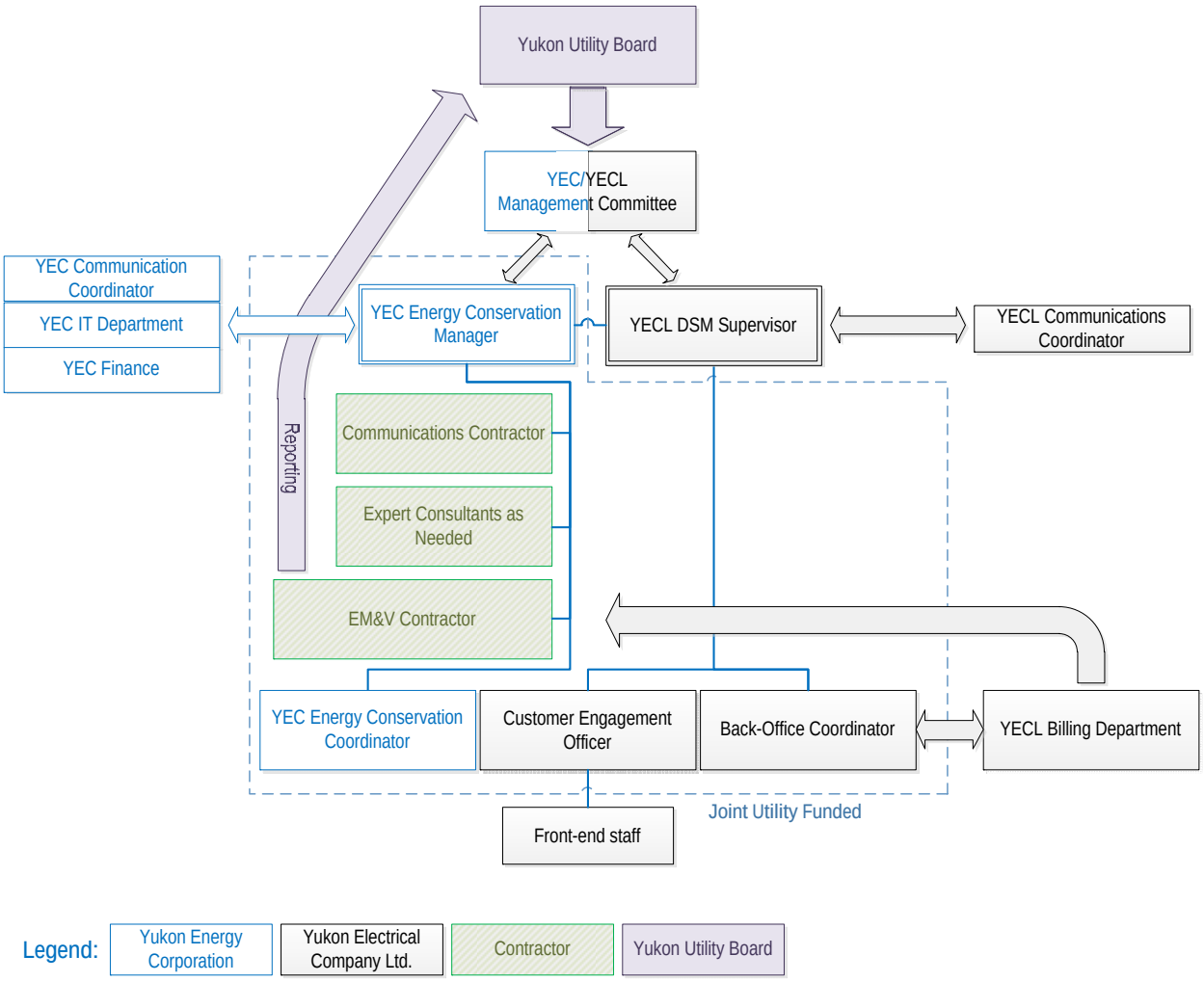
Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YEC Energy Conservation Coordinator	YEC	• Is integrated in the launch team and works on the tasks laid out by the Launch Contractor. • Work closely with the Launch Contractor to: o Develop the tracking system/program database. o Build the technical reference manuals (deemed savings and stipulated net-to-gross ratio) and connect it to the tracking system. o Finalize the KPIs and targets. o Prepare templates for the quarterly and yearly performance reports. o Draft the operations manual. • Support the YEC Energy Conservation Manager with the drafting of the first quarterly and yearly program reports.
YECL Billing Department	YECL	• Collaborates with the Launch Contractor to establish the YECL on-bill incentive payment procedures for when the recipient of the incentive is direct YECL customer.
YEC Finance	YEC	• Supports the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS). • Collaborates with the Launch Contractor to establish the YEC incentive payment procedures for when the participants are eligible direct YEC customers.
YEC Information Technology (IT) Department	YEC	• Support the YEC Energy Conservation Coordinator and the Launch Contractor during the development of the tracking system. • Collaborate with the Launch Contractor and YECL IT department to store the tracking database, share it, protect it, and manage levels of access. • Collaborate with the Communication Contractors and the Launch Contractors to develop the inCharge website, and determine where the inCharge website will be hosted (on YEC service, YECL server or a third-party server – to be determined).
Communications Contractor	Contractor for YEC	• Develop the inCharge website, managed by the YEC Energy Conservation Manager and with the support of YEC IT department as needed. • During the preparation and launch (phase 1 to 3): work on the branding, templates and graphic materials, and anything requiring significant graphic design. • Support YEC Energy Conservation Manager and YECL DSM Supervisor in the review and finalization the communication plan. • Design POP and other educational materials as part of the Residential Promotion of Low-Cost Energy-Efficient Products.
YEC Communications Coordinator	YEC	• Support development of communications material (examples: website content, print-media content and social media if any) with YEC Energy Conservation Manager.
YECL Corporate Communications & Customer Relations	YECL	• Support development of communications material (examples: website content, print-media content and social media if any) with YECL DSM Supervisor. • Recruit and hire a DSM supervisor sometime between Y1-Q1 and Y1-Q3.

Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YECL DSM Supervisor (New hire)	YECL	• Jointly accountable with the YEC Energy Conservation Manager for deliverables (eg schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Jointly responsible for the public relations activities on behalf of inCharge with YEC Energy Conservation Manager. • Jointly responsible for development of communications content (examples: website content, print-media content and social media if any) with YEC Energy Conservation Manager and supported by the YEC and YECL communications coordinators. • Review and approve the final detailed work plan to be created by the Launch Team. • Review and approve the final communication plan. • Quality control/quality assurance of all of the communication materials being generated by the Launch Team and the Communications Contractor. • Recruit and hire a Customer Engagement Officer and a Back-Office Coordinator sometime between Y1-Q2 and Y2-Q1. • Work on the first direct engagement plan with the Customer Engagement Officer, develop direct-engagement key performance indicators (KPIs) and goals, and monitor KPIs.
Customer Engagement Officer (New hire)	YECL	• Work on the first direct engagement plan. • Test-drive the direct engagement communications resources (brochures, website content, etc.) with early actual customers, and provide feedback (quality, effectiveness, how easy to understand, etc.). • Gather data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS as presented in Section 2.2. • Collaborate with YECL billing department and the Launch Contractor to establish the YECL on-bill incentive payment procedures for when the recipient of the incentive is a direct YECL customer.
Back-Office Coordinator (New hire)	YECL	• Process the very first transactions, and work with the Energy Conservation Coordinator and Launch Contractor to resolve the issues that arise.

4.2 Roles and Responsibilities during Full Program Operation

Exhibit 7 outlines the anticipated organization of key roles once the program is fully launched and is in full operation. An explanatory note is presented in tabular format following the chart.

Exhibit 7: Organization Chart during Full Program Operation



Position	Payroll	Role/Responsibility during Full Operation
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Coordinate with YECL DSM Supervisor to ensure business needs are met. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Prepare reports and documents to be filed with the YUB under the supervision of YEC/YECL Management Committee (most likely made of extracts from the aforementioned reports,

Position	Payroll	Role/Responsibility during Full Operation
		budgets and plans). • Procurement of the services of the EM&V contractors, Communications Contractor, and expert consultants when needed. • Coordination between the positions or resources shown in Exhibit 7. • Update the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the contractors' deliverables. • Update the communication tactic calendar on a sliding quarterly basis. • Monitor the customer engagement KPIs. • Work jointly with the YECL DSM Supervisor to update and approve the engagement plan updates by the YECL Customer Engagement Officer. • Public relations activities on behalf of inCharge brand. • Continuous development of new communications content, or update of existing contents (as needed): website, print-media, social media if any, etc.
YEC/YECL Management Committee	YEC or YECL	• Review and comment on the reports, budgets and planning drafted by the YEC Energy Conservation Manager and the YECL DSM Supervisor. • Provide directions to the YEC Energy Conservation Manager and YECL DSM Supervisor on the reports and documents to be filed with the YUB, review and approve these documents and file them. • Work with the YEC Energy Conservation Manager and YECL DSM Supervisor to address comments from the YUB and interveners.
YEC Energy Conservation Coordinator	YEC	• Maintain the tracking system, control the quality of the data inputted into the system. • Extract reports from the accounting system and the tracking system for the YEC Energy Conservation Manager (KPIs, charts, etc.). • Supports the YEC Energy Conservation Manager with the development of quarterly or annual reports. • Coordinate with YEC Finance to pay incentive to YEC direct customers. • Support the YEC Energy Conservation Manager with EM&V, with selecting the EM&V contractor, and with the coordination with the EM&V contractor. • Support the YEC Energy Conservation Manager with selecting technical experts as needed, and with the coordination with these experts. • Provide technical assistance to all inCharge personnel as needed.
YEC Communications Coordinator		• Support public relations and communications needs of inCharge brand. • Support YEC DSM Supervisor as needed.
YECL Back-Office Coordinator	YECL	• Handles applications and completion forms. • Feeds the tracking system with transactional information as required in the operation manual. • Proceeds with in-situ verification of a few transactions (spot-check verifications that are going to be selected randomly). • Coordinate with YECL Billing department and provide support, as needed, for YECL on-bill incentive payments.

Position	Payroll	Role/Responsibility during Full Operation
YECL Billing Department	YECL	• Proceed with incentive payment (on-bill or otherwise) for when the recipient of the incentive is direct YECL customer based on procedures established during startup. • Send utility billing data to EM&V Contractor as needed and when needed, directly to the contractor, and under a confidentiality agreement with the contractor.
YEC Finance	YEC	• Support the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS). • Proceed with incentive payment (on-bill or otherwise) for when the recipient of the incentive is direct YEC customer based on procedures established during startup.
YEC Information Technology (IT) Department	YEC	• Support the Energy Conservation Coordinator with tracking system maintenance. • Collaborate with the Communication Contractor to maintain the inCharge website.
Communications Contractor	Contractor for YEC	• Support YEC Energy Conservation Coordinator in the update of the list of communication tactics and production schedule. • Design communications materials as required by the YEC Energy Conservation Coordinator – anything requiring substantial graphic design.
YECL DSM Supervisor	YECL	• Jointly accountable with the YEC Energy Conservation Manager for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Review and approve of the detailed work plan when updated by the YEC Energy Conservation Manager. • Work jointly with the YEC Energy Conservation Manager to update and approve the engagement plan updates by the YECL Customer Engagement Officer. • QC/QA of all of the communication materials being generated by the YEC Energy Conservation Manager and the Communications Contractor. • Supervise the update of the engagement plan with the Customer Engagement Officer, monitor key performance indicators (KPIs) and update the goals. • Support corporate social responsibilities and inCharge brand.
YECL Communications Coordinator	YECL	• Support public relations and communications needs of inCharge brand. • Support YECL DSM Supervisor as needed.

Position	Payroll	Role/Responsibility during Full Operation
Customer Engagement Officer	YECL	• Carry out direct customer engagement according to the plan. • Supports participants with their transaction face to face, on the phone or through emails. • Log the events or actions in order to compute the engagement KPIs. • Log program transactions (for example: program applications) that YECL channels to YECL Back-Office Coordinator with time stamps. • Track incentive reimbursements coming from YEC; and make sure there are no discrepancies between the tracking information of YECL and that of YEC. • Regarding the above, investigate any discrepancy as soon as possible. • Gathers data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS as presented in Section 2.2.
Yukon Utility Board (YUB)	YUB	• Look out for the interests of the rate payers and authorize the use of rate payers' monies on DSM. • As such, the YUB requires DSM to be implemented in a rigorous, cost-effective and optimal manner. All documents filed with them should demonstrate these attributes. • They achieve the above by asking questions and making comments on the reporting and planning documents filed with them.
Evaluation, Measurement and Verification (EM&V) Contractor	Contractor for YEC	• Finalize the evaluation, measurement and verification plan. • As part of the above, review the tracking system and procedures, and recommend changes to maximize the value of EM&V. • As part of the above, establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, and so on. • As part of the above, collect some additional market baseline information if and as needed. • Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6). • As part of the above, do some quality control/quality assurance of the program impacts as computed by the tracking system. • Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.
Expert Consultants	Contrac-tors for YEC	• Provide technical assistance to participants as part of the General Service HE Refrigeration program element. • Deliver training course to Yukon equipment or service providers (if any, when needed). • Hands-on training to Yukon equipment or service providers (if any, when needed). • Support inCharge staff as required, to update the prescriptive incentive lists (both the incentive level and the eligible products). • Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).

4.3 Goals and Performance Tracking

Program performance will be monitored by comparing key performance indicators (KPIs) with pre-established targets.

The program accounting system and tracking systems should report on the following KPIs for each program element:

1. Number of transactions and number of business days of average processing time
2. Incentive disbursement cost
3. Program cost and administration cost
4. kWh and kW savings (gross)[5]
5. Number of transactions being verified on site (to be determined with the YEC Energy Conservation Coordinator, triggered and coordinated with the YECL Back-Office Coordinator, and then validated by the EM&V Contractor)
6. Direct-engagement indicators (to be determined with the YECL engagement officer)
7. Indirect communications indicators (to be determined with YEC Energy Conservation Manager and the communications contractor)

The targets for KPIs (1) to (4) above were set out in the projection tables presented in the Program Design Document. KPIs (5) to (7) will be established during program set up in collaboration with the core program staff.

The utilities will aim at achieving a total net electricity savings that is equal to, or above, the totals presented in the DSM portfolio projections at a total cost that is equal to, or below, the totals presented in the DSM budget (See the Program Design document). However, the utilities will have the flexibility to move targets and budgets between the DSM program elements to adapt to changing market conditions and early program results. Quarterly budgets will also be flexible as long as annual budgets are complied with.

In addition to information for tracking the KPIs above, the team will designate a limited number of information items to be collected for administrative and technical verification, as well as planning and strategic decision purposes (e.g. participant information, house/building type, etc.).

All KPIs computed by the DSM accounting system and the tracking system(s) will be verified by a third-party evaluation, measurement and verification (EM&V) contractor. The EM&V contractor will also validate the approach to on-site verification, the information items being collected through the applications and forms for verification purposes, and the market indicators to be monitored.

In addition to the KPIs stated above, a few market indicators will be established and documented through EM&V to test the effectiveness of the delivery mechanisms and to seek evidence of market effects of the DSM portfolio.

The program activities will be tracked and performance will be reviewed according to the reporting and planning schedule presented in Section 4.4.

[5] The tracking system will report on net impact if a deemed net-to-gross ratio is used.

4.4 Operational Reporting and Planning

The DSM portfolio activities will be coordinated through an annual performance reporting and work planning process, supported by quarterly updates to the annual planning.

The YEC Energy Conservation Manager and YECL DSM Supervisor will draft the reports and plans, present them, discuss them and request approval by the YEC/YECL Management Committee. Together, the YEC Energy Conservation Manager, YECL DSM Supervisor and the YEC/YECL Management Committee will prepare summaries of the reports and plans to be filed with the YUB.

There are five components to the DSM operation management and accountability mechanisms:

- **Performance report(s) to the YEC/YECL Management Committee**: Lays out KPIs against targets, explanations and justification for these results, and other strategic information gathered.
- **Work plan(s) to the YEC/YECL Management Committee:** Presents the tasks that need to be accomplished in the next quarter and in the next year. Also, it will present an updated strategic orientation and the corrective actions that need to be taken in light of the performance of the DSM portfolio and its different program elements.
- **Budget(s) to the YEC/YECL Management Committee:** Presents the resources that are needed to accomplish the tasks stated in the work plans, highlights discrepancies from the initial budget, and provides a justification for the changes if any (including but not limited to DSM cost-effectiveness).
- **DSM summaries to the YUB:** Composed of relevant extracts from the aforementioned reports, plans and budgets.
- **Third-party EM&V reports to the YUB:** The three reports are the final EM&V plan (during Q1 of Y2), the process evaluation study (sometime between Q4 of Y2 and Q2 of Y4), and the impact evaluation study (Q4 of Y5). The EM&V reports will present a rigorous estimation of the impacts in terms of kWh and kW and constructive criticism of utility-based DSM operation in the Yukon.

Exhibit 8 summarizes the reports, plans and budgets, together with a preliminary schedule and preview of the content of each. EM&V reports have been included to show the differences in content between the internal performance reports and those developed by the third-party EM&V contractor.

Exhibit 8: Summary of Operational Reports, Plans, and Budgets

Document	Schedule	KPIs against targets, including tracked impact estimates	Update on detailed action plan, incoming communication tactics, & engagement plan	Qualitative on strategic DSM development (outside the KPIs)	Updated strategic orientations	Update of detailed program - element targets	Updated contingency plan	Financial report against budget (time, expenses, incentives)	Budget re-allocation between quarters and program elements	Next-year total DSM portfolio budget estimate	Next-year detailed budget for all of the program elements	Combined ex-post & ex-ante DSM cost-effectiveness modeling	KPIs and market indicators in full MBO framework	Forward-looking improvement recommendations	Verified program impact estimates
Internal Performance Reporting & Planning															
Annual Progress Report	January 31st for the next fiscal year	X		X				X				X			
Annual Work Plan	January 31st for the next fiscal year		X		X	X	X								
Preliminary Annual Budget	September									X					
Annual Detailed Budget	January 31st for the next fiscal year										X				
Quarterly Report	30 days following end of the quarter	X	X					X	X						
YUB Annual Summary	30 days following end of the quarter	X	X	X	X	X	X	X			X	X			
Third-Party Evaluation, Measurement and Verification															
Final EM&V Plan	Q1 of Y2												X		
Process Evaluation Rep.	Mid-course. Btw Y2-Q4 & Y4-Q2											X	X	X	
Impact Evaluation Rep.	Q4 of Y5											X	X	X	X

It is expected that the YUB Annual Summary will be a concise document made of extracts from the annual progress report, the annual work plan, and the annual detailed budget.

The Launch Contractor can support with reporting during the first year of operation in the following way: the Launch Contractor will draft and deliver their own quarterly and annual reports and plans to the YEC Energy Conservation Manager and YECL DSM Supervisor; who will then build on these drafts to generate the reports and plans for the YEC/YECL Management Committee.

The accounting system will be adapted and the tracking system will be built to generate tables and charts that will be integrated in the reports[6], plans and summaries in a seamless fashion. The accounting system and tracking system should make the reporting and planning less effort intensive. Besides, the quarterly report should be relatively lean and require a low level of effort.

The three last reports presented in Exhibit 8 are to be drafted by the EM&V Contractor, not the utilities, and will be filed directly with the YUB. However, the YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL Management Committee will be able to read early drafts of these reports, ask questions, highlight potential errors or omissions, and make comments on the reports before it is sent to the YUB.

All of the internal reports and plans (that is: the first four types of reports in Exhibit 8) should be made accessible to the EM&V Contractor under the confidentiality terms of the EM&V contract.

4.5 Contingency Plan

Exhibit 9 shows the project risks that have been identified by the team. These are the risks that will be monitored and reported on throughout the project in the contingency plan. Project risks are events that could affect the outcome of the DSM portfolio. These could include time, cost, quality, operational, cultural, communications, governance, stakeholders, resources, technology, etc. Severity and probability ratings will be reassessed by the team as necessary.

The risks were ranked from the most important to the least by using a ranking system that is presented in Exhibit 9.

Exhibit 9: Risk Analysis

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Communication	Wrong messages are sent to the market during program operation	M	H	6	Communication work will involve the YEC & YECL Communication Coordinators. Direct engagement will be done by the YECL Customer Engagement Officer under the supervision of YECL DSM Supervisor with support from YECL Corporate Communications.
Communication	Target audience not buying in to the key messages of the program	M	H	6	Early and extensive engagement with end-users, with market actors, and with stakeholders. We will listen, screen out outlying opinions, analyze and react. Sufficient program budget allocations to communications and engagement. Continuity of the communication activities ensured by cross-cutting communication coordinator.

[6] The combined ex-post & ex-ante DSM cost-effectiveness modeling can be done using the cost-effectiveness model used at the program design stage. It is not worth investing in building cost-effectiveness modeling capabilities inside the tracking system.
[7] High (H), Medium (M) and Low (L) are respectively worth 3, 2 and 1.
The Risk Rating is the result of: Severity x Probability

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Commu-nication	YEC Energy Conservation Manager stops actively managing external communications because his/her attention is focused on extinguishing fires (examples: fixing issues with the transactional materials, the tracking system, or dealing with specific large transactions)	M	H	6	Work closely with the YEC and YECL Communications Coordinators; if possible have the communications coordinators play a larger role. Delegate to the YEC or YECL Communications Coordinator his/her functions of surveillance and communication planning whenever he/she has to focus elsewhere. Rely on the YEC Energy Conservation Coordinator and core utility staff to fix issues with the transactional and operational infrastructure and tracking system, address issues with incentive payment and cash flow, and have the Back-Office Coordinator deal with the EM&V Contractor. Delegate as many reporting tasks as possible to the core utility staff.
Commu-nication	Company branded initiatives leverage inCharge branding and create customer confusion	L	M		Avoid similar or overlapping activities between companies and inCharge.
Technical	Residential innovative heating systems fail to perform in the Yukon and backfire	H	M	6	The implementation approach of the Residential Innovative Heating program element includes a 3-year pilot phase before we anticipate being able to turn it into a full-scale incentive program. It is a prudent implementation approach. We believe that inCharge can achieve and document a few successful installs, identify capable installers and, then build communication materials based on these.
Opera-tional	Delays happen with certain program elements during start up and hold back the entire program portfolio	M	H	6	In principle, the Utilities will be using a comprehensive implementation approach with all program elements being taken to market within the same 4-phase timetable. In reality, a few program elements will cause delays because the launch team will be confronted to unforeseeable issues. As long as these delays are only a few days, the program elements can remain in sync. However, if the delays start becoming problematic then the YEC Energy Conservation Manager will be allowed to let the schedule for some problematic program element slip compared to that of other program elements. The overall schedule might become out of synch but this could be preferable than delaying the launch of the entire DSM portfolio.
Opera-tional	Misunderstandings arise between YEC & YECL on role, responsibilities and/or on who is to blame for disappointing KPIs (this tends to happen when targets are not met)	H	M	6	Clear assignation of roles and responsibilities as per section 4.1 and 4.2 of the PIP. These sections should be revisited and refreshed on an annual basis as part of the annual performance reporting and planning cycle so they remain fresh in the mind of everyone in the core team. YECL Customer Engagement Officer is to produce an engagement plan, and agree on it with YEC.
Opera-tional	The resulting DSM program design fails to deliver expected results	M	M	4	The Utilities used evidence-based program design, and established realistic targets based on conservation potential review and a bottom up reality check. The Utilities claim the right to adjust program offerings mid-stream, after determining the root causes of low participation.

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Operational	Program participation uptake not picking up as planned	M	M	4	Sufficient budgets allocated to marketing and communications. Continuity of communication and marketing activities, and continuous tracking of uptake – See above how we will manage to ensure that communications is managed on a continuous basis. Flexibility to use other budgets and allocate them to marketing and communication in order to intensify the communication activities if and when needed.
Operational	Inaccuracy of the impact estimates (kWh and kW)	M	M	4	Support of the Launch Contractor's energy engineers to re-visit the deemed savings for the prescriptive conservation measures. Carefully plan, design and develop the tracking system and procedures; diligent and timely inputting of program data in the tracking system. Support from seasoned expert consultants to validate the engineering calculation of custom conservation measures and projects, and/or to carry out project-level measurement and verification. Third-party EM&V including validation of the deemed savings of the prescriptive measures early in the operation of the program (Y2-Q1) and final validation of the estimates generated by the tracking system during the impact evaluation study (Y5-Q3).
Planning	Approved plan, targets and schedule may not be achievable	M	M	4	Monitor milestones, monitor KPIs and execute project plan. Raise issues with the YEC/YECL management committee when presenting the quarterly or annual report. The reporting and planning procedures presented in Section 4.3 and 4.4 are flexible. Use this flexibility to change the strategy and change the approach to reach the total targets for the DSM portfolio.
Communication	Bad press	L	H	3	Communication work will jointly involve the YEC and YECL communication coordinators. Continuous monitoring of public relations activities handled by YEC Energy Conservation Manager, in coordination with YECL DSM Supervisor, YEC communication coordinator and YECL Corporate Communications & Customer Relations. Direct engagement of largest end-users by YECL DSM Customer Engagement Officer, direct engagement of key suppliers and retailers by YEC Energy Conservation Manager.
Operational	Understanding of needs/expectations of the Utilities by the Launch Contractor and/or the EM&V contractor	L	H	3	Carry out brief weekly or bi-weekly progress report (phone call or otherwise). Generate meeting minutes. The market characterization reports, the program design document, the PIP and the draft EM&V plan should be provided to the contractors. The KPIs and the market indicators are clearly laid out in the draft MBO framework presented in the draft EM&V plan. The MBO framework will be updated with the launch contractor, and then with the EM&V contractor.

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Operational	Non-eligibility of participants	L	M	2	The Launch Team will create simple and clear eligibility criteria. The Launch Team will develop clear program internal procedures to validate eligibility. The core program team will lay out the eligibility criteria in an accessible fashion in the communications materials. The Customer Engagement Officer and/or the YECL front-end staff will be accessible to answer questions on the program. The YEC Energy Conservation Manager, YECL DSM Supervisor and engagement coordinator will provide clear information and training to YECL front-end staff so that they can provide the most up to date and accurate information to customers. This should be built in the communication plan and list of communication tactics and documented. The Customer Engagement Officer will be accessible for the prospective participants to ask questions.
Operational	Fraud from participants or lack of diligence from the program team to prevent fraud or errors	M	L	2	We seek to minimize fraud, not prevent it entirely. The mitigation measure must commensurate with the size of the rebate or incentive. We included site verification in some cases; on a spot-check basis and selected randomly. The Launch Team will lay out clear internal procedures to validate the information provided by the participants (when practical); the back office will have to comply with these and document his/her work. Compliance with the program internal validation procedures will be checked by the EM&V Contractor through the documentation left behind.
Operational	Operational areas outside of DSM (finance, IT, communications) may not have the resources to do their part	L	M	2	Ensure that the YEC/YECL Management Committee is involved to mediate issues and facilitate transition.
Planning	The appropriate resources won't be available to complete the project on time	L	L	1	Identify and secure appropriate resources with sufficient lead time. Update work plan at least quarterly (more often if possible) and validate availability of resources then raise resource constraint issues with the YEC/YECL Management Committee.

4.7 Information Flow Mapping

This section lays out three "maps" of the information flows between involved actors: YEC, YECL, the markets, the EM&V contractors, and the YUB. These three maps, without being completely exhaustive, should cover a large and representative portion of DSM portfolio activities, and include:

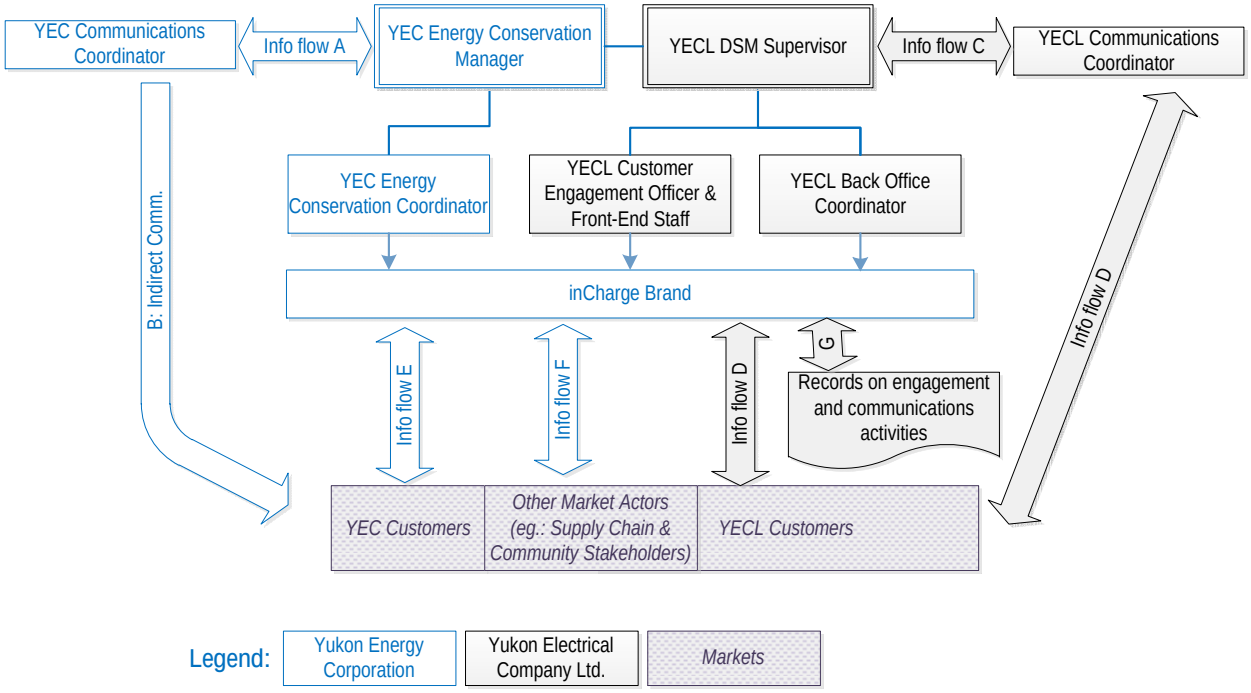
- Communications and direct engagement information-flow diagram
- Application processing and incentive payment information-flow diagram, and
- Performance reporting and EM&V information-flow diagram.

These three maps are provided below.

Communications and Direct Engagement Information Flow

The proposed information flow for communications and direct engagement activities is presented in Exhibit 10. An explanatory note is presented in tabular format following the chart.

Exhibit 10: Communications and Direct Engagement Information Flow Diagram



Explanation of the Information Flows – Communications and Direct Engagement

	Marketing and Communications
A	The marketing and communications plan, implementation of communications tactics, the inCharge website and print-media content will be developed jointly by YEC and YECL. The marketing and communications work will be carried out according to a number of communication KPIs; e.g. number of clicks on the inCharge website, number of participants at inCharge branded public events (public relations opportunities, etc.), number of brochures distributed, etc. Later, the YEC Energy Conservation Manager and the YEC Communication Coordinator will report on

Explanation of the Information Flows – Communications and Direct Engagement

	their performance based on the plan. The Manager will need to log some statistics and events to compute the KPIs throughout the year. It is more practical to keep this log separated from the main program tracking system. The communication KPIs will be determined by the YEC Energy Conservation Manager during the program setup.
B	YEC and YECL will jointly deliver messages to both YECL customers, YEC customers and other market actors indirectly through marketing and communication tactics. The YEC Energy Conservation Manager and the YEC Communication Coordinator will work with YECL to plan and develop bill inserts.

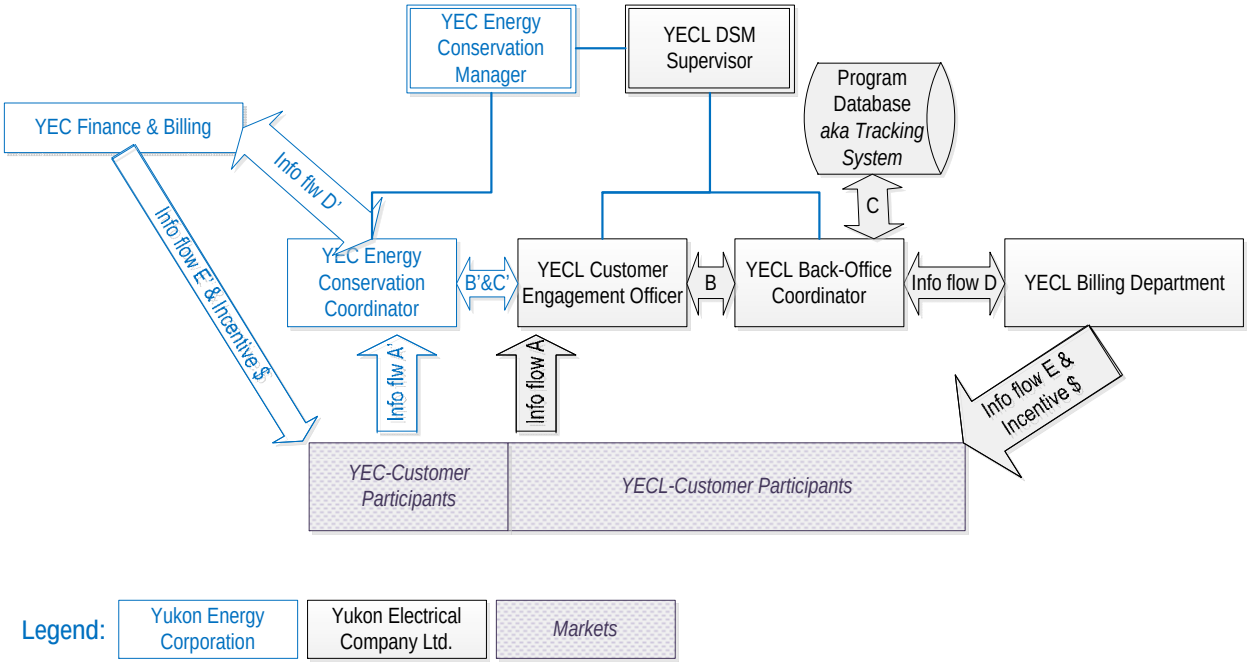
Direct Customer Engagement

C	The YECL DSM Supervisor, YECL Communications and the YECL Customer Engagement Officer will plan customer engagement events together with YEC Energy Conservation Manager.
D	The YECL Customer Engagement Officer will engage directly with YECL customers through the inCharge brand to educate them about electricity conservation, inform them about the DSM offerings and ease them into one or many of the program elements. YECL customers represent a large portion of the electricity end-user in the Yukon; hence YECL is responsible for most of the direct-engagement work. The YECL Communications Coordinator and YECL DSM Supervisor will support as needed. The YECL Customer Engagement Officer will create an Engagement Plan that – for the most part – will consist of direct engagement KPIs and targets. The YECL Customer Engagement Officer will share the engagement plan document and discuss it with the YECL DSM Supervisor to make sure that the level of activity matches expectations and will deliver sufficient uptake. The engagement plan will not include any confidential information on YECL customers. The YEC Energy Conservation Manager and YECL DSM Supervisor will jointly finalize the engagement plan The YECL Customer Engagement Officer will need to log some statistics and events to compute the KPIs thorough the year. It is more practical for YECL to keep this log separate from the main program tracking system.
E	The YEC Energy Conservation Coordinator and/or the YEC Energy Conservation Manager will engage directly with YEC customers through the inCharge brand to educate them about electricity conservation, to inform them about the DSM offerings and ease them into one or many of the program elements. It is assumed that very little engagement planning will be needed on the YEC side because much fewer electricity end-users are customers of YEC than of YECL.
F	The utilities will engage directly with other market actors through the inCharge brand to educate them on electricity conservation, to plan and execute indirect communication and education tactics, and to support them with the participation processes. It is expected that many market actors will be useful trade allies and will help promote the program.
G	There is a need for keeping records on engagement and communication activities in order to generate the KPIs that will be used to manage the program. Core utility staff will be asked to log most of engagement and communication activities, consistent with the planning and the KPIs that will be decided on.

Application Processing and Incentive Payment Information Flow

The proposed information flow for processing and incentive payment activities is presented in Exhibit 11. An explanatory note is presented in tabular format following the chart.

Exhibit 11: Application Processing and Incentive Payment Information-Flow Block Diagram



Explanation of the Information Flows – Application Processing and Incentive Payment

A	The YECL Customer Engagement Officer will engage directly with YECL customers, inform them about the offerings, ease them into one or many program elements, help them with the program applications, forms and documentation, and retrieve the paperwork from the participant. YECL customers will send in their DSM applications and forms either through YECL Customer Engagement Officer, the front-end staff or directly to the inCharge website.
B	The program applications will be passed on to the YECL Back-Office Coordinator who will process them. Processing involves[8]: checking completeness of the paperwork, checking participant and technical eligibility, checking that the forms contain the necessary signatures, in certain cases verifying the engineering calculations backing the energy savings claim, establishing the incentive amount, getting the authorization to proceed with the payment of the incentive, issuing notices to inform the participants about the status of their application, retrieving the information contained in the paperwork and input it into the tracking system, documenting the processing work into the tracking system.

[8] The process described above is scalable. For example, a small incentive application will be streamlined and involve far less steps.

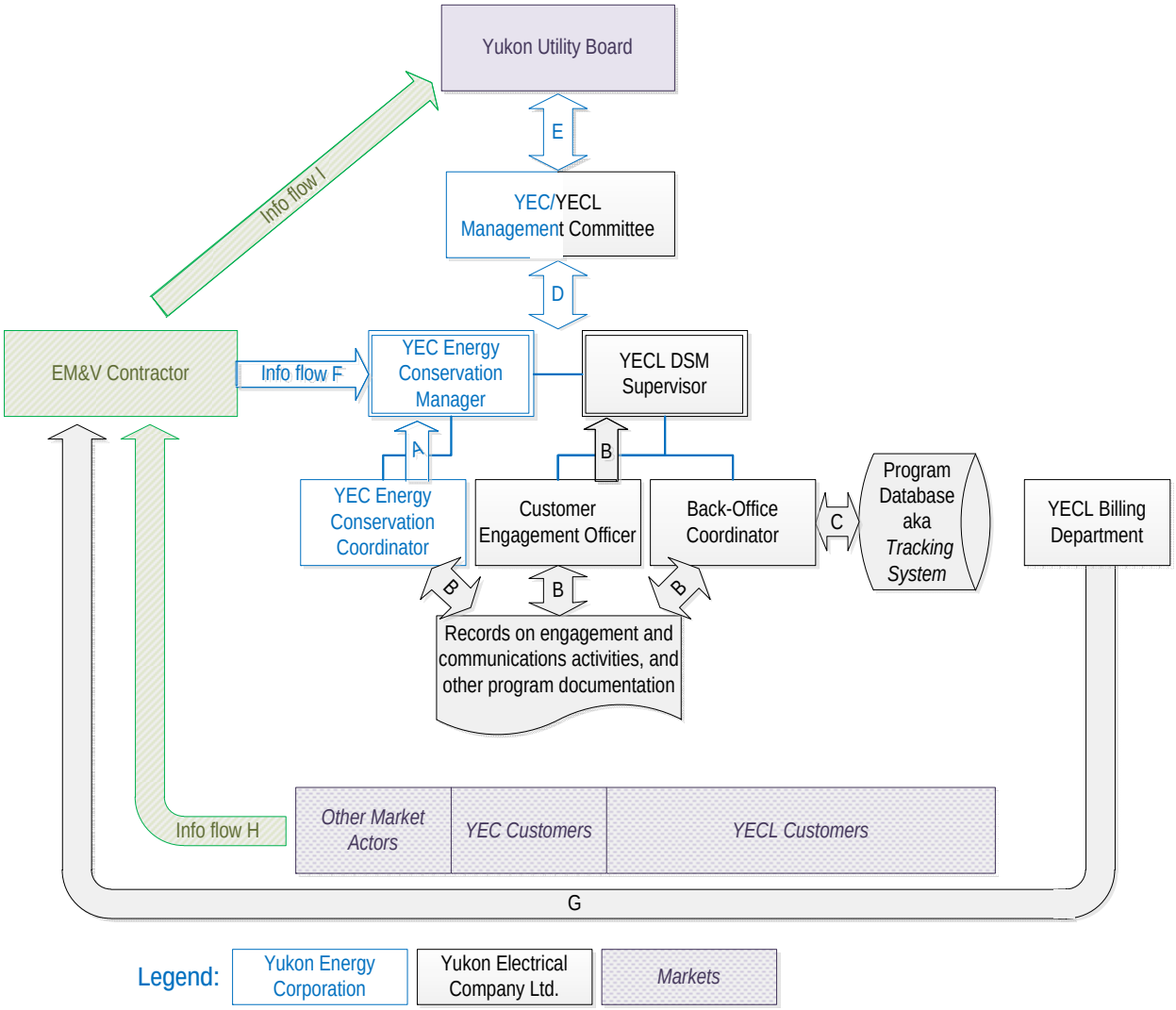
Explanation of the Information Flows – Application Processing and Incentive Payment

C	The tracking system/program database will be able to store the following data and generate reports based on it: time stamps for all transactions; participant information (names, contact information, etc.); type(s) and number of prescriptive conservation measures; description and claimed savings associated with custom conservation measures or projects; eligible savings as validated by the back-office coordinator; total measure or project cost; YECL/YEC account number and any other information used to verify participant eligibility; information used to verify technical eligibility of products or project; status of the application; claimed incentive amount; eligible incentive amount after validation; whether it is a YEC account or a YECL account; trade ally involved in the file; building or house type; how they learned about the program; and, whether the application came in directly or through YECL.
D	Whenever an incentive payment is authorized the YECL Back-Office coordinator will issue an internal form and send it to YECL Billing Department. The internal form will clearly lay out: the name of the recipient and electricity account information; the total amount of the incentive; any relevant explanatory notes – in particular if the incentive amount is not what the participant had originally claimed. The YECL Customer Engagement Officer will coordinate with the YECL Billing Department to make sure that the incentive gets paid to the recipient diligently.
E	The incentive payment can be credited on the participant energy bill or sent otherwise. It could be accompanied with an explanatory notes (mentioned in (D) if the incentive amount is not what the participant had expected. Once the payment is issued; the YECL Billing Department is expected to provide a form of feedback/confirmation to the YECL Customer Engagement Officer in order to update the database and generate the payment timestamps.
A'	The YEC Energy Conservation Coordinator will engage directly with YEC customers; ease them into one or many program elements; help them; and retrieve the paperwork from the participants. YEC customers will send in their DSM applications and forms either through YEC Energy Conservation Coordinator or directly to the inCharge website. YEC customers are much fewer than the YECL customers; therefore, it is expected that the volume of applications and the information flows described from A' to E' will be smaller.
B' & C'	The YEC Energy Conservation Coordinator will work with YECL Back-Office Coordinator to process the applications; and feed the tracking system.
D'	The YEC Energy Conservation Coordinator will work with YEC Finance to get the incentive payment made to the YEC eligible participants.
E'	YEC Finance will send incentive payments to YEC eligible participants by sending them a cheque. The YEC Energy Conservation Coordinator will work with the YECL Back-Office Coordinator to make sure that the payment status is properly inputted and time-stamped in the program database.

Performance Reporting and EM&V Information Flow

The proposed information flow for performance reporting and EM&V activities is presented in Exhibit 12. An explanatory note is presented in tabular format following the chart.

Exhibit 12: Performance Reporting and EM&V Information-Flow Block Diagram



Explanation of the Information Flows – Performance Reporting and EM&V

Performance Reporting, Planning and Budgeting

A	The YEC Energy Conservation Coordinator will extract relevant statistics, indicators, tables, and charts from the tracking system and send it to the YEC Energy Conservation Manager.
B	The YECL Customer Engagement Officer and YEC Energy Conservation Coordinator will compute the direct engagement KPIs for the quarter or year and send them to the YEC Energy Conservation Manager who will produce a combined report. All members of the inCharge team will log and keep records of communication, training and engagement activities in a format that is consistent with the KPIs that will be agreed on at the program set-up stage. Communication, training and engagement KPIs were suggested on a preliminary basis as part of the EM&V plan.

Explanation of the Information Flows – Performance Reporting and EM&V

C	The YECL Back-Office Coordinator will be responsible for inputting participation data into the tracking system with technical support from the YEC Energy Conservation Coordinator. As mentioned in (A), the YECL Back-Office Coordinator and YEC Energy Conservation Coordinator will work together to extract relevant reports from the tracking system as needed to support the management of the DSM portfolio.
D	The YEC Energy Conservation Manager will prepare a set of documents as described in Section 4.4 with the support of the YEC Energy Conservation Coordinator. They include: Annual Progress Report; Annual Work Plan; Annual Detailed Budget; and Quarterly Report. These documents are presented to the YEC/YECL Management Committee and will be reviewed, discussed and finalized.
E	The YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL Management Committee will develop an Annual Summary that will be filed with the YUB (See description in Section 4.4).

Third-Party Evaluation Measurement and Verification

F	The YEC Energy Conservation Manager will work with the YEC Energy Conservation Coordinator to make the following data and documentation available to the EM&V contractor under confidentiality terms and conditions: the program database (or extract of that database); the engagement, training and communication records and KPIs; the CPR reports; the focus paper; the market characterization reports; the program design final report; the PIP; the draft EM&V Plan; the progress reports; work plans and budgets; and all of the communication materials. The core program operation team must also be available for interviews with the EM&V contractor.
G	The YECL Billing Department will be solicited to provide billing information to the EM&V Contractor about participants and non-participant monthly electricity consumption and peak demand for 24 to 36 months before participation in the program and then 24 to 36 months after. The EM&V Contractor might have to sign a confidentiality agreement with YECL.
H	The EM&V Contractor will carry out surveys, site visits and other market research activities to gather the market intelligence needed to perform its process evaluation and impact evaluation.
I	The EM&V Contractor will file three reports with the YUB: the Final EM&V Plan; the Process Evaluation Report; and the Impact Evaluation Report. (See Section 4.4). The YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL management committee will be able to read early drafts of these reports, ask questions, highlight potential errors or omissions, and make comments on the reports before it is sent to the YUB.

5. Communication Plan

Section 5 provides a description of the target audiences, communication approach and goals, and key messages that will be used to strategically promote program understanding and uptake. This preliminary communication plan was designed to build on existing customer service functions and recognizes the importance of nurturing existing relationships between utilities and customers and supply-side market actors.

5.1 High-Level Communication Objectives

The high-level communication objectives are to:

1. Generate participation in the General Service and the Residential programs.
2. Raise awareness and educate Yukon residents and businesses on how adopting energy-efficient practices and equipment can save both power and money.
3. Increase YEC/YECL customer satisfaction.

To achieve the three objectives above the Utilities will seek to collaborate and develop formal or informal alliances with supply-side actors and other stakeholders to deliver information and energy efficient consumer products to the electricity end-users. The same groups may also partake in the implementation of energy efficiency projects.

5.2 Audiences

Major market actors that will need to be engaged to successfully operate the General Service and Residential programs in the Yukon include the following:

- Building owners/managers and institutional building facility managers
- Developers, architects and general contractors
- Residential customers
- Electrical distributors/independent lighting distributors
- Lighting designers
- Electrical contractors
- HVAC designers
- HVAC and control contractors
- Retailers
- External stakeholders[9]

[9] Examples: Yukon Housing Corporation, Yukon Conservation Society, the City of Whitehorse, Energy Solutions Centre, the Yukon Contractor Association, the Association of Professional Engineers of Yukon, Yukon College, and the Whitehorse Chamber of Commerce.

As shown in Exhibit 13, some of these groups will be engaged as supply-side market actors and others will be target participants for various program elements. All of these groups will be target audiences for education and engagement activities.

Exhibit 13: Audiences and Relevant Program Elements

Audience	Relevant Program Elements	Supply-Side	Participant
Building Owners/Managers and Institutional Building Facility Managers	GS Lighting Redesign and Equipment Incentive		✓
	GS High-Efficiency Refrigeration		✓
	GS Energy Star Computer Incentive		✓
Developers, Architects, Contractors	GS New Construction Incentive	✓	
	GS Lighting Redesign and Equipment Incentive		✓
	Res. LED Lighting & Automotive Heater Timer Rebates		✓
Residential Customers	Res. LED Lighting & Automotive Heater Timer Rebates		✓
	Res. Low-Cost Energy Efficient Products		✓
Electrical/lighting Distributors	GS Lighting Redesign and Equipment Incentive	✓	
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
	GS Energy Star Computer Incentive		✓
Lighting Designers	GS Lighting Redesign and Equipment Incentive	✓	
	GS Energy Star Computer Incentive		✓
Electrical Contractors	GS Lighting Redesign and Equipment Incentive	✓	
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
HVAC/Control Designers	GS New Construction Incentive	✓	
	GS Energy Star Computer Incentive		✓
HVAC/Control Contractors	GS New Construction Incentive	✓	
Retailers	GS Lighting Redesign and Equipment Incentive		✓
	GS High Efficiency Refrigeration	✓	✓
	GS Energy Star Computer Incentive	✓	✓
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
	Res. Low-Cost Energy Efficiency Products	✓	

Program communication considerations for these key players as well as internal and external stakeholders are discussed in Appendix B. Communication activities will be strongly influenced by the fact that Whitehorse is a small close-knit community where news about good or bad installations is disseminated quickly and is remembered for a long time. It is also recognized that, generally speaking, market actors prefer the direct engagement approach.

Please refer to the Market Characterization reports for more details about each of these groups.

5.3 Approach

This section presents the approach that will be employed to address the objectives of the program launch and delivery. Detailed engagement, training and communication strategies are provided in the Program Design document. Please refer to Section 3.3.6 for the General Services Program and Section 4.3.6 for the Residential Program.

Public Launch of the Program Offerings

Tactics supporting the public launch of the DSM portfolio should be integrated and planned with care. Some media tactics will be used to vehicle information on both programs, and others should be used for one or the other.

Prior to the launch the team will:

- Develop extensive web content to explain the benefits, modalities, eligibility criteria and participation process of each of the offerings.
- Prepare a detailed memo containing the same information as above for the YEC and YECL front-end staff on the new DSM portfolio. That memo should be accompanied by a formal presentation. YECL and YEC front-end staff needs to be ready to answer most questions that their customers will have after the launch.
- Design information pieces (specific type, i.e. brochures, information sheets, bill inserts, etc. to be determined once a detailed communication strategy is prepared) prior to the launch and will include similar content to that for the inCharge website.

The communications contractor will be involved in the tactics that require significant graphic design.

For the launch of the inCharge DSM portfolio (both program) the team will:

- Make a public announcement regarding the launch of inCharge. This could be done through a media release, media briefing, or other methods deemed appropriate.
- Leverage existing public relations opportunities around the expected date of launch where to go public and where to present the entire DSM portfolio.

To increase uptake of the General Service Program during the first two quarters of operation (or as required) the following tactics may be employed:

- YECL and YEC may consider sending program information to the General Service customers along with their utility bills.
- YECL Customer Engagement Officer will call upon YECL largest accounts (building owners) to offer a face to face presentation of the offerings. Similarly, YEC will arrange in-person meetings with their large customers.
- The program team will engage with General Service supply-chain actors and prospective trade allies directly to present them the program and seek to collaborate – as described below.
- The team will distribute the aforementioned information brochures to the General Service supply-chain actors for them to pass along to their customers and use them to boost their sales.
- The team will carry out joint events with interested applicable trade and commerce organization (See external stakeholders in Appendix B) – as described below.

The program team will carry out the above tactics to increase uptake of the Residential Program during the first two quarters of operation (or as required). However, the supply-chain actors and the community and non-profit organizations require additional consideration. In addition to the tactics above, the launch of the Residential Program will also include:

- The team will design and create point-of-purchase materials for the retailer to display. See details about the work to be done with retail store managers below.
- YECL Customer Engagement Officer will carry out extensive community outreach and develop an energy efficiency community network in their service areas. YEC may do the same in their service area – more about this tactic is presented below.

Once passed the first two quarters of operation, the level of intensity of the engagement, marketing and communication will decrease. However, a continuous stream of new tactics should be planned and carried out. The team may choose to re-use the tactics presented above, and also:

- General Service and Residential customers will be able to sign in the inCharge website to receive news, information and updates about the programs. With time, a database of contact information will be built and the team will be able to reach out to people who signed up through newsletter and email blasts.
- As the General Service Program unfolds, early success stories will be captured and shared (where approved by the participants) through project case studies disseminated through the website, public relation opportunities, YECL and YEC direct customer engagement, and trade/commerce events.
- Public information campaigns will be used periodically throughout the operation of the program to support continued awareness of the Residential Program offerings.

Direct Engagement with Supply-side Market Actors

During the program portfolio launch, the team will engage with the appropriate supply chain actors as listed above and described in Appendix B (Retailers are discussed in the following section). The following tactics are being envisioned:

- The program team will provide technical support on the use of the standardized incentive calculation tool and the program forms and procedures.
- Direct engagement will be used (including emails, phone calls and in-person meetings) and hard-to reach contractors will be engaged through health and safety training from the Utilities and through collaboration with distributors.
- Hands-on training will be offered on advanced electricity efficiency lighting design and on the business aspects of electricity efficiency.
- Upon request from the local supply-side market actors the Utilities will act as a broker to procure technical expertise from highly specialized lighting and HVAC experts recruited from throughout North America.
- The supply-side market actors will be able to consult with these experts to work on specific projects and improve their design skills and professional competencies.

Supply-side market actors are also encouraged to participate in program offerings where eligible. Improving the energy efficiency of supply-side market actors' homes and offices allows them to share valuable personal success stories.

Direct Engagement with Retailers

The program team will develop partnerships with retail store managers to work with them to:

- Add low-cost energy efficient items to their shelves if they haven't already.

- Identify certain models that yield higher customer satisfaction and thus provide an incentive to increase shelf space for these models.
- Install point-of-purchase materials (Education on Low-Cost EE Product).
- Share EE product sales data (in units, and on a confidential basis) to monitor the impact of the program.

Large retailers will also be engaged as key participants in the suite of General Service program offerings as retail stores are energy intensive. Installations at large retail facilities would provide high-profile examples of successful program participation.

Direct Engagement with Major Building Owners/Managers

The YECL Customer Engagement Officer will offer personalized support to building owners/managers perhaps with the support of the Back-Office Coordinator and/or Expert Consultants. YEC will offer similar support for its customers. The owners/managers are the prospective participants in all General Service program components; thus, engaging them is critical to the success of the program. The Utilities intend to use the following tactics to engage them:

- Customized support to plan investment in assets and to identify which buildings to develop projects in.
- Customized support to optimize decisions on implementation and procurement approaches.
- Support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).

Direct Engagement with Residential Customer and Creation of a Community Network

The YECL Customer Engagement Officer and YEC will engage individuals who are interested in energy conservation and are leaders among their peers to eventually join the community network.

At the start of the program operation the engagement officer will meet them at community events, at in-store events, workshops, and any opportunity for direct engagement. It is expected that distributing low-cost EE products free of charge will be a draw to initiate and build relationships with prospective EE ambassadors as well as an opportunity to demonstrate the products to their friends and relatives.

The Utilities will leverage the energy efficiency community to:

- Provide information to the communities on the low-cost EE products in a direct fashion.
- Disseminate educational and informational materials on low-cost EE products.
- Test certain low-cost products and gather customer satisfaction feedback.
- Extend the advertisement on the low-cost EE products through word-of-mouth marketing.

Training for Supply-Side Actors

The Utilities intend to provide technical support in the form of hands-on training where needed. The main training offerings that have been identified include:

- Program forms and procedures for Lighting Supply Channels.
- Program forms and procedures for HVAC and New-Construction Supply Channels.
- Electricity efficiency lighting design.
- Business aspect of electricity efficiency, including: energy audits; business cases; energy performance contracting; and energy efficiency financing.

It is expected that the knowledge provided to the supply-side actors will be passed on to many of their clients. Thus, the training should in turn educate Yukon residents and businesses on the benefits of energy efficiency and increase uptake in program offerings.

Events and Public Relations Opportunities

The Utilities propose to sponsor and attend trade shows and other events that gather local building owners/managers and/or supply-chain actors. Initially, the utilities will support existing trade events that have to do with lighting design or advanced HVAC design.

The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories and share their lessons learned. Practitioners should be able to network within the Yukon and also with manufacturer reps and agents from outside the Yukon. The Utilities will also use the trade events to advertise the DSM portfolio.

To support the events, the Utilities envision using one or several of the following tactics:

- Small grants to support the logistics of the events.
- Attendance and presentation of content at the events, such as case studies, information on program offerings, etc.
- Dissemination of information about the events through other media used by the Utilities (email blast, newsletter, website content, direct engagement, etc.).
- Support for well-known experts in the lighting or HVAC field to come to the Yukon (perhaps representatives from the IES or from ASHRAE) in the form of an allocation to pay for transportation and accommodations.
- Engagement with manufacturer reps or agents in Northern BC and Northern Alberta with the intention of convincing them to attend the events. (For example, the Utilities could invite reps from OSRAM/Sylvania, GE, Philips, Canlite, Lithonia, Cooper, Mitsubishi, Honeywell, Siemens, Johnson Controls, Lennox, etc.).

With time and if early initiatives are successful, the Utilities will explore the possibility of financing and organizing an annual stand-alone trade event in Whitehorse.

6. Financial Plan

Section 6 provides a summary of the operational budget, together with a concise description of the main cash flows between the utilities and the ratepayers as well as between utilities.

6.1 Budget

The budget shown in Exhibit 14 has been organized using the breakdown structure (BBS) that is identical to the WPS presented in Section 2.2. We recommend basing the DSM finance tracking on this BBS and assigning the program staff time and expenses (including delivery and EM&V contractors) to one of the cost categories shown previously in Exhibit 2.

Exhibit 14 Portfolio Budget Including Government Buildings

Budget Breakdown Structure	Year-1 Quarterly Budget ($1,000s)				5-Year Annual Budget Projections ($1,000s)					
	Y1-Q1	Y1-Q2	Y1-Q3	Y1-Q4	Year 1	Year 2	Year 3	Year 4	Year 5	TOTAL
GRAND TOTAL	$140	$258	$234	$193	$824	$1,240	$1,393	$1,266	$1,480	$6,203
WP1 General Service Program	$62	$129	$122	$82	$395	$628	$928	$765	$796	$3,512
WP1.1 Program Management	$15	$19	$26	$27	$88	$80	$79	$82	$84	$413
WP1.2 Engagement, Training and Communication	$12	$64	$58	$39	$174	$240	$229	$174	$179	$996
WP1.3 Lighting Redesign Study & Equipm't Incentive	$14	$18	$17	$4	$53	$150	$328	$367	$337	$1,235
WP1.3.1 Time & Materials	*$14*	*$18*	*$14*	*$1*	*$47*	*$15*	*$35*	*$40*	*$38*	*$174*
WP1.3.2 Incentive Disbursement	*$0*	*$0*	*$3*	*$3*	*$6*	*$135*	*$294*	*$327*	*$299*	*$1,062*
WP1.4 Energy Star Computer Incentive	$7	$9	$7	$12	$35	$76	$125	$0	$0	$236
WP1.4.1 Time & Materials	*$7*	*$9*	*$7*	*$6*	*$29*	*$40*	*$68*	*$0*	*$0*	*$137*
WP1.4.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$6*	*$6*	*$35*	*$57*	*$0*	*$0*	*$98*
WP1.5 High-Efficiency Refrigeration	$7	$9	$7	$0	$23	$77	$139	$74	$147	$460
WP1.5.1 Time & Materials	*$7*	*$9*	*$7*	*$0*	*$23*	*$77*	*$7*	*$74*	*$15*	*$197*
WP1.5.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$132*	*$0*	*$132*	*$263*
WP1.6 New Construction Incentive	$7	$9	$7	$0	$23	$6	$27	$68	$49	$173
WP1.6.1 Time & Materials	*$7*	*$9*	*$7*	*$0*	*$23*	*$0*	*$2*	*$28*	*$4*	*$58*
WP1.6.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$0*	*$0*	*$6*	*$25*	*$39*	*$45*	*$115*
WP2 Residential Program	$78	$129	$111	$111	$429	$468	$465	$501	$430	$2,294
WP2.1 Program Management	$32	$33	$18	$21	$104	$74	$66	$75	$77	$396
WP2.2 Engagement, Education and Communication	$23	$30	$30	$30	$113	$130	$134	$138	$142	$657
WP2.3 LED Lighting & Auto. Heater Timer Rebates	$17	$17	$7	$9	$51	$77	$79	$80	$81	$367
WP2.3.1 Time & Materials	*$17*	*$17*	*$2*	*$3*	*$39*	*$26*	*$27*	*$28*	*$29*	*$150*
WP2.3.2 Incentive Disbursement	*$0*	*$0*	*$5*	*$7*	*$12*	*$51*	*$52*	*$52*	*$52*	*$217*
WP2.4 Promotion of Low-Cost EE Products	$6	$49	$47	$46	$148	$157	$155	$152	$104	$715
WP2.4.1 Time & Materials	*$6*	*$44*	*$38*	*$26*	*$114*	*$109*	*$112*	*$115*	*$74*	*$523*
WP2.4.2 Incentive Disbursement	*$0*	*$5*	*$9*	*$20*	*$34*	*$48*	*$43*	*$36*	*$30*	*$192*
WP2.5 Innovative Heating Systems Initiative	$0	$0	$9	$4	$14	$31	$32	$56	$26	$159
WP2.5.1 Time & Materials	*$0*	*$0*	*$4*	*$4*	*$9*	*$22*	*$23*	*$33*	*$8*	*$94*
WP2.5.2 Incentive Disbursement	*$0*	*$0*	*$5*	*$0*	*$5*	*$9*	*$9*	*$24*	*$19*	*$65*
WP3 Evaluation, Measurement and Verification	$0	$0	$0	$0	$0	$144	$0	$0	$253	$397

6.2 Cash Flows and Payment Schemes

Four DSM cash flows are anticipated:

1. **The administration cost paid for by YEC –** Two FTEs that are members of the core staff; some direct expenses; and most of the contractor fees.
2. **The incentives paid by YEC to YEC customers –** This is expected to be a small fraction of the incentive disbursements.
3. **The administration cost paid for by YECL –** Two FTEs as members of the core staff; one corporate FTE and some direct costs.

4. **The incentives paid by YECL to YECL customers –** This is expected to be most of the incentive payment.

Incentives and costs will be reconciled between the two utilities on a quarterly basis

YEC DSM costs (administration and incentive) are going to be funded by the ratepayers because the cost will be presented to the YUB as part of the rate filing. This is going to be further defined by the outcome of the Joint Panel on DSM as part of the YECLs next general rate application.

YECL DSM costs (administration and incentive) are going to be funded by the ratepayers because the cost will be presented to the YUB as part of the rate filing. This will also be defined by the outcome of the Joint Panel on DSM as part of the YECLs next general rate application.

Appendices

Appendix A: Year-1 Detailed Action Plan

Please see attached – DSM Program Detailed Action Plan PDF

Appendix B: Audience Descriptions

Major market actors that will need to be engaged to successfully operate the General Service and Residential programs in the Yukon include the following:

- Building owners/managers and institutional building facility managers
- Developers, architects and general contractors
- Residential customers
- Electrical distributors/independent lighting distributors
- Lighting designers
- Electrical contractors
- HVAC designers
- HVAC and control contractors
- Retailers

Program communication considerations for these key players, as well as internal and external stakeholders, are discussed below.

Building Owners/Managers and Institutional Building Facility Managers

Commercial building owners/managers and institutional building managers will be targeted as major potential participants for the General Services program offerings. There are 8 large property managers/owners in the Yukon, located predominantly within Whitehorse. Building owners and managers, looking to better understand how to manage their energy bills, could find it fairly puzzling given that they work with various contractors that each has a vested interest. Owners/managers would have a higher level of trust in a third party such as the Utilities than in a supplier, so direct communication from the Utilities may be better received.

Commercial building owners/managers often have more freedom to make purchasing decisions than government building managers. Government facility managers must work within a budget decided by Council or the Territory and must follow the procurement policies. It is important to communicate the business case for program participation not only to facility managers but to City Council and other decision makers.

Building Developers, General Contractors and Architects

Developers and architects are already working in a market interested in buying environmentally-friendly homes. Words such as SuperGreen, electricity efficiency, energy conservation and ENERGY STAR are commonly used in sales pitches and collateral materials.

There are roughly 5-10 housing developers in the Yukon and developers, general contractors and architects are extremely busy. Direct and efficient communication is important with this group.

Residential Customers

Eligible participants for the Residential program include: owners of detached houses; town/row houses; condominium units; and mobiles homes located in the Yukon who shop in Yukon retail stores. The program also includes online shoppers, landlords and renters. This is a group of approximately 20,000 shoppers. The primary source of information used to make purchase decisions is the store where the purchase is made. In-store marketing material should be clear and prominent. Other key sources of information for shoppers are friends and relatives as well as websites displaying user-generated content.

The relationship between landlords and tenants was discussed in Section 4.1.4 of the Program Design report. Given the significant split-incentive barrier between landlords and tenants this segment will not be main focus for engagement.

Some individuals are particularly passionate about or interested in improving the energy efficiency of their home. These individuals will likely be interested in developing a collaborative relationship with the Utilities.

Electrical Distributors

There are only two electrical distributors in the Yukon: EECOL and Guillevin, as well as a few independent lighting distributors selling to the Yukon residential and building sectors. These distributors are key market actors. Electrical distributors often maintain relationships with a variety of market actors situated both upstream and downstream in the supply chain including: lighting designers; building owners; electrical contractors and manufacturer agents and representatives. Electrical distributors are keen to participate in programs and are easier to engage than electrical contractors because new incremental projects mean increased sales.

Lighting Designers

Only two firms offer lighting design services by professional electrical engineers. These will be very important partners for the Lighting Redesign Incentive program offerings. These designers prefer direct engagement through email, phone calls, and in-person meetings.

Electrical Contractors

Electrical contractors active in the territory are smaller regional firms with a handful of employees. There are approximately 26 electrical contractors in the Yukon and they are a hard-to-reach group of people as they are very busy and are on the road much of the time.

Depending on the type of project, electrical contractors may have a contractual relationship with a general contractor or directly with the building owner. Unless their clients are very specific about the fixtures and lamps that they want, contractors have a great deal of influence on design choices. Electrical contractors make quick and conservative design decisions based on equipment they are accustomed to. There is an opportunity to make energy efficiency design decisions easier for them by providing simple and concise educational material with a suggested prescriptive approach; and/or to provide compensation if they need to spend more time making better design decisions.

HVAC and Control Designers

There are two firms offering HVAC/control design services in the Yukon, with design teams lead by senior mechanical engineers. Designers are facing a high demand for their services. Designers are the market actors most likely to be in a position to educate the end users about the lifecycle cost benefits of energy efficient designs. However, with very little competition and a large amount of new construction projects there is little incentive for them to proactively offer innovative and efficient designs. HVAC and Control designers prefer direct engagement and would be interested in trade shows or events if they saw value in terms of learning and networking opportunities.

HVAC and Control Contractors

For the most part control systems and HVAC equipment are sold locally by contractors. There are roughly 16 HVAC/control contractors serving the Yukon. Control contractors in the Yukon are smaller local firms with a handful of employees. The two control contractors in the Yukon consist of a Honeywell dealer and a Siemens dealer. Controls contractors have long-term

maintenance contracts therefore they have significant direct interactions with owners. This provides an opportunity to educate the energy end-users.

Retailers

Retail store managers are both target program participants for the General Services program and target supply-side market actors for the Residential program (and in some cases the General Services program). Most retail stores are concentrated in Whitehorse and consist of large "big-box" retail stores as well as smaller independent stores. Store managers are more knowledgeable about DSM programs in other jurisdictions than other actors because they often have branches in other parts of Canada and the United States. They are keen to participate in joint initiatives with the utilities but are dealing with a human resource shortage.

Internal Stakeholders

All YEC/YECL staff will need to be aware of the DSM portfolio to support program communication.

External Stakeholders

External stakeholders are other organizations and individuals in the Territory that may play a role (intentionally or unintentionally) in promoting or injuring the DSM program portfolio. The key stakeholders include: the Yukon Housing Corporation; the City of Whitehorse; Energy Solutions Centre; the Yukon Contractor Association; the Association of Professional Engineers of Yukon; Yukon College; and the Whitehorse Chamber of Commerce.

The City of Whitehorse is a very sustainability and conservation minded organization (including energy) and has been involved in CPR workshops and YEC's energy planning charrettes. The General Services and Residential programs would benefit from ongoing engagement with the City on a number of fronts including: as a program participant and advocate; and as an informant of any building Bylaw changes that would affect commercial developments.

The Energy Solutions Centre (ESC) is a branch of the Yukon Government's Department of Energy, Mines and Resources. ESC participates in the design of energy policies and delivers energy programs and projects for Yukon citizens, other government departments, First Nations, municipalities and businesses. The YEC/YECL DSM portfolio has been designed to minimize duplication and potential customer confusion. This will remain an ongoing consideration.

Among other programs and services, Yukon Housing is the delivery agent for the EcoEnergy Program through the federal Office of Energy Efficiency. They also manage the Green and SuperGreen endorsement label for new residential construction energy performance. Yukon Housing also delivers a variety of training courses for residential developers and construction contractors. As for the ESC, the YEC/YECL DSM portfolio was designed to avoid duplication but it will remain an ongoing consideration.

The Yukon Contractor Association's primary objective is the overall improvement of the industry and the provision of services to their members. The Association is credible among contractors and provides several communication channels with members (who are generally difficult to reach).

The Association of Professional Engineers of Yukon (APEY) is a non-profit trade association representing professional engineers. APEY has very limited resources and did not show a high degree of interest in being an active stakeholder in YEC/YECL DSM portfolio. It may be valuable to keep the APEY aware of program activities as growth in Yukon Engineers' knowledge of energy efficiency is beneficial to the program.

Yukon College is the only post-secondary provider in the Yukon. Although the College has limited resources, it may be valuable to engage the College in the training aspect of the General Services and Residential program offerings and as a program participant.

The Whitehorse Chamber of Commerce is a local organization of businesses whose goal is to further the interests of businesses. The Chamber organizes many events, which could be used to advertise the General Services program offerings to their members and provide a forum for energy efficiency education and discussion.

CW-YECL-30

Reference: Depreciation, YECL Application, page 7-1

On lines 15-17, YECL indicates that it has requested reinstatement of a provision for future removal and site restoration in depreciation rates. The City requires information to understand the impact of the change.

Request:

(a) Please provide Schedules 7.1 through 7.5 with the impact of the reinstatement of future removal and site restoration in depreciation rates removed.

(b) Please confirm that there are no adjustments to reserve differences to catch up on uncollected provisions for future removal and site restoration. If not confirmed, please provide an analysis summarizing the impact of changes to reserve differences for 2013-2015.

Response:

(a) Please refer to CW-YECL-30(a) Attachment 1.

(b) Not confirmed. Schedule 2B of the Gannett Fleming report provides a calculation of the true-up of accumulated depreciation variances between the Calculated Accumulated Depreciation and the Booked Accumulated Depreciation related to net salvage as of December 31, 2011. It is noted that the Accumulated Depreciation variance as determined in this depreciation study has grown substantially since the time when a similar calculation was made in the 2008 depreciation study. Gannett Fleming notes that this growth in variance is in large part caused by the suspension of collection of net salvage over the period since 2008. Given that no provision for salvage has been collected since 2008, the amount of the true-up request as indicated in Schedule 2B is the result of a number of factors including (in large part) the suspension of the collection of net salvage since 2008.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.1 - Depreciation Expense Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1	General Provision	S. 7.2, 7.3,7.4 L.51	3,585	3,892	4,108	4,559	4,641	5,081	5,901	6,743	3,760	4,067
2	Amortization of Differences	S.7.5 L. 51	(382)	(382)	(382)	(382)	(382)	(402)	(402)	(402)	(382)	(382)
3	Vehicle Depreciation Capitalized	S.8.6 L. 21	(22)	(64)	(43)	(48)	(67)	(75)	(82)	(87)	(24)	(24)
4	Total Depreciation Expense	S.1.1 L.12	3,181	3,446	3,683	4,129	4,192	4,604	5,417	6,254	3,354	3,661

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.2 - 2013 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2013 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2013 Total Depreciation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		263	2.18%	6	180	2	8
4	423 00	Hydro Resv, Dams & Waterways		2,375	2.18%	52	1,627	18	70
5	425 00	Hydro Generators		2,676	2.44%	65	1,833	22	87
6	426 00	Hydro Accessory Electrical Equip		158	2.34%	4	108	1	5
7	427 00	Hydro Misc Equip		69	3.70%	3	47	1	4
8		Total Production - Hydro		5,539		130	3,794	44	174
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,238	2.79%	63	491	7	70
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	3.08%	97	688	11	108
13	445 00	Generating Equipment & Prime Mover - Other		7,270	3.86%	280	1,594	31	311
14	446 00	Accessory Electric Equipment - Other		2,077	3.32%	69	455	8	77
15	447 00	Misc. Power Plant Equipment - Other		794	2.92%	23	174	3	26
16		Total Production - Diesel		15,517		532	3,402	60	592
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.05%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,331	1.51%	20	102	1	21
24	473 00	Poles, Towers & Fixtures		34,533	2.40%	830	2,559	31	861
25	474 00	Overhead Conductor		22,282	2.31%	515	1,703	20	535
26	474 10	Services - Overhead		2,979	2.34%	70	228	3	73
27	475 00	Underground Conductor		22,880	2.41%	550	1,732	21	571
28	475 10	Services - Underground		3,097	2.61%	81	237	3	84
29	476 10	Meters		1,984	7.65%	152	542	-	152
30	476 30	AMR - Meters		68	7.31%	5	-	-	5
31	477 10	Substation Equipment		3,131	2.50%	78	239	3	81
32	478 10	Street Lighting		9,600	3.43%	329	396	7	336
33	478 20	Sentinel Lights		285	2.99%	9	-	-	9
34	479 10	Line Transformers		28,058	2.42%	678	2,032	25	703
35		Total Distribution Plant		130,227		3,317	9,770	114	3,431
36									
37		General Plant							
38	482 00	Structures & Improvements		3,634	2.63%	96	1,124	15	111
39	483 00	Office Furniture & Equipment		194	5.70%	11	11	-	11
40	483 20	Computer Equipment		47	18.73%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		2,954	8.59%	254	432	19	273
42	485 00	Tool & Work Equipment		843	6.33%	53	86	3	56
43	486 00	Communication Structures & Equipment		938	5.50%	52	65	2	54
44	488 20	Company Housing		475	2.66%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,251	4.00%	-	650	26	26
47	493 00	Demand Side Management		-	10.00%	-	481	48	48
48	496 00	Software		2,204	10.00%	220	705	35	255
49		Total General Plant		12,541		708	3,555	148	856
50									
51		Plant Studied		165,208		4,715	20,522	366	5,081
52		Plant Not Studied - Land		380					
53		Total Plant	S.8.6 L.10	165,588					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.3 - 2014 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2014 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2014 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		442	2.53%	11	157	2	13
4	423 00	Hydro Resv, Dams & Waterways		4,001	2.36%	95	1,421	17	112
5	425 00	Hydro Generators		4,508	2.52%	114	1,601	20	134
6	426 00	Hydro Accessory Electrical Equip		266	2.60%	7	94	1	8
7	427 00	Hydro Misc Equip		116	4.06%	5	41	1	6
8		Total Production - Hydro		9,334		232	3,315	41	273
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,729	2.84%	78	649	9	87
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,826	3.17%	121	910	14	135
13	445 00	Generating Equipment & Prime Mover - Other		8,865	3.94%	349	2,109	42	391
14	446 00	Accessory Electric Equipment - Other		2,532	3.52%	89	602	11	100
15	447 00	Misc. Power Plant Equipment - Other		968	2.96%	29	230	3	32
16		Total Production - Diesel		18,919		666	4,501	79	745
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.04%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,432	1.50%	21	113	1	22
24	473 00	Poles, Towers & Fixtures		37,092	2.40%	890	2,844	34	924
25	474 00	Overhead Conductor		23,985	2.31%	554	1,887	22	576
26	474 10	Services - Overhead		3,206	2.34%	75	252	3	78
27	475 00	Underground Conductor		24,612	2.40%	592	1,921	23	615
28	475 10	Services - Underground		3,334	2.60%	87	262	3	90
29	476 10	Meters		2,525	8.09%	204	(377)	-	204
30	476 30	AMR - Meters		68	7.13%	5	1,580	56	61
31	477 10	Substation Equipment		3,370	2.50%	84	265	3	87
32	478 10	Street Lighting		9,996	3.41%	341	945	16	357
33	478 20	Sentinel Lights		285	2.93%	8	-	-	8
34	479 10	Line Transformers		30,090	2.41%	726	2,364	29	755
35		Total Distribution Plant		139,997		3,587	12,057	190	3,777
36									
37		General Plant							
38	482 00	Structures & Improvements		4,758	2.67%	127	315	4	131
39	483 00	Office Furniture & Equipment		205	6.67%	14	9	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		3,386	8.79%	298	868	38	336
42	485 00	Tool & Work Equipment		930	6.67%	62	137	5	67
43	486 00	Communication Structures & Equipment		1,003	6.67%	67	11	-	67
44	488 20	Company Housing		475	2.65%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		481	10.00%	48	522	26	74
48	496 00	Software		2,909	10.00%	291	7	-	291
49		Total General Plant		16,096		1,005	1,869	73	1,078
50									
51		Plant Studied		185,730		5,518	21,742	383	5,901
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	186,110					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.4 - 2015 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2015 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2015 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		600	2.64%	16	-	-	16
4	423 00	Hydro Resv, Dams & Waterways		5,422	2.44%	132	-	-	132
5	425 00	Hydro Generators		6,110	2.56%	156	-	-	156
6	426 00	Hydro Accessory Electrical Equip		360	2.70%	10	-	-	10
7	427 00	Hydro Misc Equip		157	4.10%	6	-	-	6
8		Total Production - Hydro		12,649		320	-	-	320
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		3,378	2.97%	100	798	12	112
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		4,736	3.28%	155	1,118	18	173
13	445 00	Generating Equipment & Prime Mover - Other		10,973	4.26%	467	2,592	55	522
14	446 00	Accessory Electric Equipment - Other		3,134	3.86%	121	740	14	135
15	447 00	Misc. Power Plant Equipment - Other		1,198	3.06%	37	283	4	41
16		Total Production - Diesel		23,420		880	5,531	103	983
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.04%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,545	1.50%	23	109	1	24
24	473 00	Poles, Towers & Fixtures		39,937	2.40%	958	2,736	33	991
25	474 00	Overhead Conductor		25,872	2.31%	598	1,825	21	619
26	474 10	Services - Overhead		3,459	2.34%	81	244	3	84
27	475 00	Underground Conductor		26,534	2.40%	638	1,855	22	660
28	475 10	Services - Underground		3,596	2.60%	94	254	3	97
29	476 10	Meters		2,148	7.40%	159	(377)	-	159
30	476 30	AMR - Meters		1,648	8.08%	133	2,283	92	225
31	477 10	Substation Equipment		3,636	2.50%	91	256	3	94
32	478 10	Street Lighting		10,941	3.42%	374	813	14	388
33	478 20	Sentinel Lights		285	2.87%	8	-	-	8
34	479 10	Line Transformers		32,454	2.41%	782	2,277	27	809
35		Total Distribution Plant		152,054		3,939	12,274	219	4,158
36									
37		General Plant							
38	482 00	Structures & Improvements		5,073	2.66%	135	305	4	139
39	483 00	Office Furniture & Equipment		214	6.67%	14	2	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		4,254	9.31%	396	730	34	430
42	485 00	Tool & Work Equipment		1,066	6.67%	71	84	3	74
43	486 00	Communication Structures & Equipment		1,014	6.67%	68	12	-	68
44	488 20	Company Housing		475	2.63%	12	-	-	12
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		1,003	10.00%	100	730	37	137
48	496 00	Software		2,916	10.00%	292	57	3	295
49		Total General Plant		17,965		1,173	1,920	81	1,254
50									
51		Plant Studied		207,472		6,340	19,725	403	6,743
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	207,852					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.5 - Amortization of Differences Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	YFR/ Curve	Life	Net Salvage	Depn. Rates	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1		Production - Hydro												
2														
3	422 00	Hydro Structures		R2	72	-10%	3.36%	(14)	(14)	(2)	(2)	(2)	(14)	(14)
4	423 00	Hydro Resv, Dams & Waterways		R3	103	-10%	3.36%	-	-	(9)	(9)	(9)	-	-
5	425 00	Hydro Generators		R3	85	-10%	3.36%	-	-	(4)	(4)	(4)	-	-
6	426 00	Hydro Accessory Electrical Equip		R3	45	-10%	3.36%	-	-	(2)	(2)	(2)	-	-
7	427 00	Hydro Misc Equip		R2	30	-10%	3.36%	-	-	(1)	(1)	(1)	-	-
8		Total Production - Hydro						(14)	(14)	(17)	(17)	(17)	(14)	(14)
9														
10		Production - Diesel												
11	442 00	Structures and Improvements - Other		R2.5	40	-10%	2.74%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		R4	35	-20%	3.00%	(8)	(8)	(9)	(9)	(9)	(8)	(8)
13	445 00	Generating Equipment & Prime Mover - Other		R2.5	26	-10%	3.69%	(40)	(40)	18	18	18	(40)	(40)
14	446 00	Accessory Electric Equipment - Other		R3	35	0%	3.00%	(15)	(15)	(10)	(10)	(10)	(15)	(15)
15	447 00	Misc. Power Plant Equipment - Other		R3	40	0%	3.15%	(2)	(2)	(3)	(3)	(3)	(2)	(2)
16		Total Production - Diesel						(71)	(71)	(10)	(10)	(10)	(71)	(71)
17														
18		Transmission												
19	457 00	Substation Equipment		R4	50	-10%	2.55%	(3)	(3)	(7)	(7)	(7)	(3)	(3)
20		Total Transmission						(3)	(3)	(7)	(7)	(7)	(3)	(3)
21														
22		Distribution Plant												
23	471 00	Land Rights		R3	75	0%	1.52%	-	-	-	-	-	-	-
24	473 00	Poles, Towers & Fixtures		R3	45	-75%	2.67%	(75)	(75)	(75)	(75)	(75)	(75)	(75)
25	474 00	Overhead Conductor		R4	45	-80%	2.69%	(24)	(24)	(37)	(37)	(37)	(24)	(24)
26	474 10	Services - Overhead		R3	45	-10%	2.62%	(7)	(7)	(7)	(7)	(7)	(7)	(7)
27	475 00	Underground Conductor		R3	45	-50%	2.11%	(5)	(5)	14	14	14	(5)	(5)
28	475 10	Services - Underground		R4	40	-10%	2.63%	(6)	(6)	(4)	(4)	(4)	(6)	(6)
29	476 10	Meters		L0	15	0%	4.06%	-	-	60	60	60	-	-
30	476 30	AMR - Meters		R2.5	15	0%	4.54%			1	1	1		
31	477 10	Substation Equipment		R4	40	-10%	2.92%	(6)	(6)	(16)	(16)	(16)	(6)	(6)
32	478 10	Street Lighting		R3	30	-10%	4.13%	(61)	(61)	(64)	(64)	(64)	(61)	(61)
33	478 20	Sentinel Lights		R2	23	0%	3.37%	-	-	(18)	(18)	(18)	-	-
34	479 10	Line Transformers		R3	45	-10%	3.04%	(69)	(69)	(84)	(84)	(84)	(69)	(69)
35		Total Distribution Plant						(253)	(253)	(231)	(231)	(231)	(253)	(253)
36														
37		General Plant												
38	482 00	Structures & Improvements		L3	40	0%	3.19%	-	-	(15)	(15)	(15)	-	-
39	483 00	Office Furniture & Equipment		SQ	15	0%	4.49%	2	2	8	8	8	2	2
40	483.20	Computer Hardware/Software		SQ	5	0%	20.00%	-	-	6	6	6	-	-
41	484 00	Transportation & Mobile Equipment		L0	12	25%	10.82%	(51)	(51)	(73)	(73)	(73)	(51)	(51)
42	485 00	Tool & Work Equipment		SQ	15	0%	6.54%	(3)	(3)	4	4	4	(3)	(3)
43	486 00	Communication Structures & Equipment		SQ	15	0%	5.79%	11	11	4	4	4	11	11
44	488 20	Company Housing		R3	40	10%	2.47%			(72)	(72)	(72)		
45	491 00	Franchise & Consent					0.00%	-	-	-	-	-	-	-
46	492 00	Licence - Fish Lake					10.00%							
47	493 00	Demand Side Management												
48	496 00	Software		S3	10	0%	10.00%	-	-	-	-	-	-	-
49		Total General Plant						(41)	(41)	(138)	(138)	(138)	(41)	(41)
50														
51		Total Amortization of Differences	S. 7.1 L. 2					(382)	(382)	(402)	(402)	(402)	(382)	(382)

CW-YECL-31

Reference: Depreciation, YECL Application, page 7-2

Starting on line 4, YECL discusses its proposal for deferral treatment of depreciation parameters. The City requires information to understand the proposal.

Request:

(a) On line 8 of page 7-2, YECL asserts that IFRS requires it to review depreciation parameters annually. Please provide the complete pronouncement of IFRS that YECL asserts require it to review depreciation parameter annually, indicating the portions that support the YECL position.

(b) Please confirm that none of the YECL affiliates, including Northland Utilities (Yellowknife), Northland Utilities (NWT), ATCO Electric, ATCO Gas, or ATCO Pipelines, have a deferral account for depreciation parameters. If not confirmed, please fully explain.

Response:

(a) Please refer to CW-YECL-31(a) Attachment 1 for a copy of International Accounting Standard (IAS) 16 Property Plant and Equipment.

IAS16.61, which states the following, requires Yukon Electrical to review its depreciation parameters annually:

> The depreciation method applied to an asset shall be reviewed at least at each financial year-end and, if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method shall be changed to reflect the changed pattern. Such a change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

(b) Confirmed.

INTERNATIONAL ACCOUNTING STANDARD 16 property, plant and equipment

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Objective

1 The objective of this Standard is to prescribe the accounting treatment for property, plant and equipment so that users of the financial statements can discern information about an entity's investment in its property, plant and equipment and the changes in such investment. The principal issues in accounting for property, plant and equipment are the recognition of the assets, the determination of their carrying amounts and the

depreciation charges and impairment losses to be recognised in relation to them.

Scope

2 This Standard shall be applied in accounting for property, plant and equipment except when another Standard requires or permits a different accounting treatment.

3 This Standard does not apply to:

(a) property, plant and equipment classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*;

(b) biological assets related to agricultural activity (see IAS 41 *Agriculture*);

(c) the recognition and measurement of exploration and evaluation assets (see IFRS 6 *Exploration for and Evaluation of Mineral Resources*); or

(d) mineral rights and mineral reserves such as oil, natural gas and similar non-regenerative resources.

However, this Standard applies to property, plant and equipment used to develop or maintain the assets described in (b)–(d).

4 Other Standards may require recognition of an item of property, plant and equipment based on an approach different from that in this Standard. For example, IAS 17 *Leases* requires an entity to evaluate its recognition of an item of leased property, plant and equipment on the basis of the transfer of risks and rewards. However, in such cases other aspects of the accounting treatment for these assets, including depreciation, are prescribed by this Standard.

5 An entity using the cost model for investment property in accordance with IAS 40 *Investment Property* shall use the cost model in this Standard.

Definitions

6 The following terms are used in this Standard with the meanings specified:

***Carrying amount* is the amount at which an asset is recognised after deducting any accumulated depreciation and accumulated impairment losses.**

***Cost* is the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognised in accordance with the specific requirements of other IFRSs, eg IFRS 2 *Share-based Payment*.**

***Depreciable amount* is the cost of an asset, or other amount substituted for cost, less its residual value.**

***Depreciation* is the systematic allocation of the depreciable amount of an asset over its useful life.**

***Entity-specific value* is the present value of the cash flows an entity expects to arise from the continuing use of an asset and from its disposal at the end of its useful life or expects to incur when settling a liability.**

***Fair value* is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (See IFRS 13 *Fair Value Measurement*.)**

An *impairment loss* is the amount by which the carrying amount of an asset exceeds its recoverable amount.

***Property, plant and equipment* are tangible items that:**

(a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

(b) are expected to be used during more than one period.

***Recoverable amount* is the higher of an asset's fair value less costs to sell and its value in use.**

The *residual value* of an asset is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs

of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.

***Useful life* is:**

(a) the period over which an asset is expected to be available for use by an entity; or

(b) the number of production or similar units expected to be obtained from the asset by an entity.

Recognition

7 The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if:

(a) it is probable that future economic benefits associated with the item will flow to the entity; and

(b) the cost of the item can be measured reliably.

8 Items such as spare parts, stand-by equipment and servicing equipment are recognised in accordance with this IFRS when they meet the definition of property, plant and equipment. Otherwise, such items are classified as inventory.

9 This Standard does not prescribe the unit of measure for recognition, ie what constitutes an item of property, plant and equipment. Thus, judgement is required in applying the recognition criteria to an entity's specific circumstances. It may be appropriate to aggregate individually insignificant items, such as moulds, tools and dies, and to apply the criteria to the aggregate value.

10 An entity evaluates under this recognition principle all its property, plant and equipment costs at the time they are incurred. These costs include costs incurred initially to acquire or construct an item of property, plant and equipment and costs incurred subsequently to add to, replace part of, or service it.

Initial costs

11 Items of property, plant and equipment may be acquired for safety or environmental reasons. The acquisition of such property, plant and equipment, although not directly increasing the future economic benefits of any particular existing item of property, plant and equipment, may be necessary for an entity to obtain the future economic benefits from its other assets. Such items of property, plant and equipment qualify for recognition as assets because they enable an entity to derive future economic benefits from related assets in excess of what could be derived had those items not been acquired. For example, a chemical manufacturer may install new chemical handling processes to comply with environmental requirements for the production and storage of dangerous chemicals; related plant enhancements are recognised as an asset because without them the entity is unable to manufacture and sell chemicals. However, the resulting carrying amount of such an asset and related assets is reviewed for impairment in accordance with IAS 36 *Impairment of Assets*.

Subsequent costs

12 Under the recognition principle in paragraph 7, an entity does not recognise in the carrying amount of an item of property, plant and equipment the costs of the day-to-day servicing of the item. Rather, these costs are recognised in profit or loss as incurred. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. The purpose of these expenditures is often described as for the 'repairs and maintenance' of the item of property, plant and equipment.

13 Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, a furnace may require relining after a specified number of hours of use, or aircraft interiors such as seats and galleys may require replacement several times during the life of the airframe. Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a nonrecurring replacement. Under the recognition principle in paragraph 7, an entity recognises in the carrying amount of

an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met. The carrying amount of those parts that are replaced is derecognised in accordance with the derecognition provisions of this Standard (see paragraphs 67–72).

14 A condition of continuing to operate an item of property, plant and equipment (for example, an aircraft) may be performing regular major inspections for faults regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised. This occurs regardless of whether the cost of the previous inspection was identified in the transaction in which the item was acquired or constructed. If necessary, the estimated cost of a future similar inspection may be used as an indication of what the cost of the existing inspection component was when the item was acquired or constructed.

Measurement at recognition

15 An item of property, plant and equipment that qualifies for recognition as an asset shall be measured at its cost.

Elements of cost

16 The cost of an item of property, plant and equipment comprises:

(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.

(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

17 Examples of directly attributable costs are:

(a) costs of employee benefits (as defined in IAS 19 *Employee Benefits*) arising directly from the construction or acquisition of the item of property, plant and equipment;

(b) costs of site preparation;

(c) initial delivery and handling costs;

(d) installation and assembly costs;

(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

(f) professional fees.

18 An entity applies IAS 2 *Inventories* to the costs of obligations for dismantling, removing and restoring the site on which an item is located that are incurred during a particular period as a consequence of having used the item to produce inventories during that period. The obligations for costs accounted for in accordance with IAS 2 or IAS 16 are recognised and measured in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*.

19 Examples of costs that are not costs of an item of property, plant and equipment are:

(a) costs of opening a new facility;

(b) costs of introducing a new product or service (including costs of advertising and promotional activities);

(c) costs of conducting business in a new location or with a new class of customer

(including costs of staff training); and

(d) administration and other general overhead costs.

20 Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item are not included in the carrying amount of that item. For example, the following costs are not included in the carrying amount of an item of property, plant and equipment:

(a) costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;

(b) initial operating losses, such as those incurred while demand for the item's output builds up; and

(c) costs of relocating or reorganising part or all of an entity's operations.

21 Some operations occur in connection with the construction or development of an item of property, plant and equipment, but are not necessary to bring the item to the location and condition necessary for it to be capable of operating in the manner intended by management. These incidental operations may occur before or during the construction or development activities. For example, income may be earned through using a building site as a car park until construction starts. Because incidental operations are not necessary to bring an item to the location and condition necessary for it to be capable of operating in the manner intended by management, the income and related expenses of incidental operations are recognised in profit or loss and included in their respective classifications of income and expense.

22 The cost of a self-constructed asset is determined using the same principles as for an acquired asset. If an entity makes similar assets for sale in the normal course of business, the cost of the asset is usually the same as the cost of constructing an asset for sale (see IAS 2). Therefore, any internal profits are eliminated in arriving at such costs. Similarly, the cost of abnormal amounts of wasted material, labour, or other resources incurred in self-constructing an asset is not included in the cost of the asset. IAS 23 *Borrowing Costs* establishes criteria for the recognition of interest as a component of the carrying amount of a self-constructed item of property, plant and equipment.

Measurement of cost

23 The cost of an item of property, plant and equipment is the cash price equivalent at the recognition date. If payment is deferred beyond normal credit terms, the difference between the cash price equivalent and the total payment is recognised as interest over the period of credit unless such interest is capitalised in accordance with IAS 23.

24 One or more items of property, plant and equipment may be acquired in exchange for a non-monetary asset or assets, or a combination of monetary and non-monetary assets. The following discussion refers simply to an exchange of one non-monetary asset for another, but it also applies to all exchanges described in the preceding sentence. The cost of such an item of property, plant and equipment is measured at fair value unless (a) the exchange transaction lacks commercial substance or (b) the fair value of neither the asset received nor the asset given up is reliably measurable. The acquired item is measured in this way even if an entity cannot immediately derecognise the asset given up. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up.

25 An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. An exchange transaction has commercial substance if:

(a) the configuration (risk, timing and amount) of the cash flows of the asset received differs from the configuration of the cash flows of the asset transferred; or

(b) the entity-specific value of the portion of the entity's operations affected by the

transaction changes as a result of the exchange; and

(c) the difference in (a) or (b) is significant relative to the fair value of the assets exchanged.

For the purpose of determining whether an exchange transaction has commercial substance, the entity-specific value of the portion of the entity's operations affected by the transaction shall reflect post-tax cash flows. The result of these analyses may be clear without an entity having to perform detailed calculations.

26 The fair value of an asset is reliably measurable if (a) the variability in the range of reasonable fair value measurements is not significant for that asset or (b) the probabilities of the various estimates within the range can be reasonably assessed and used when measuring fair value. If an entity is able to measure reliably the fair value of either the asset received or the asset given up, then the fair value of the asset given up is used to measure the cost of the asset received unless the fair value of the asset received is more clearly evident.

27 The cost of an item of property, plant and equipment held by a lessee under a finance lease is determined in accordance with IAS 17.

28 The carrying amount of an item of property, plant and equipment may be reduced by government grants in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*.

Measurement after recognition

29 An entity shall choose either the cost model in paragraph 30 or the revaluation model in paragraph 31 as its accounting policy and shall apply that policy to an entire class of property, plant and equipment.

Cost model

30 After recognition as an asset, an item of property, plant and equipment shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation model

31 After recognition as an asset, an item of property, plant and equipment whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. Revaluations shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period.

32–33 [Deleted]

34 The frequency of revaluations depends upon the changes in fair values of the items of property, plant and equipment being revalued. When the fair value of a revalued asset differs materially from its carrying amount, a further revaluation is required. Some items of property, plant and equipment experience significant and volatile changes in fair value, thus necessitating annual revaluation. Such frequent revaluations are unnecessary for items of property, plant and equipment with only insignificant changes in fair value. Instead, it may be necessary to revalue the item only every three or five years.

35 When an item of property, plant and equipment is revalued, any accumulated depreciation at the date of the revaluation is treated in one of the following ways:

(a) restated proportionately with the change in the gross carrying amount of the asset so that the carrying amount of the asset after revaluation equals its revalued amount. This method is often used when an asset is revalued by means of applying an index to determine its replacement cost (see IFRS 13).

(b) eliminated against the gross carrying amount of the asset and the net amount restated to the revalued amount of the asset. This method is often used for buildings.

The amount of the adjustment arising on the restatement or elimination of accumulated

depreciation forms part of the increase or decrease in carrying amount that is accounted for in accordance with paragraphs 39 and 40.

36 If an item of property, plant and equipment is revalued, the entire class of property, plant and equipment to which that asset belongs shall be revalued.

37 A class of property, plant and equipment is a grouping of assets of a similar nature and use in an entity's operations. The following are examples of separate classes:

(a) land;
(b) land and buildings;
(c) machinery;
(d) ships;
(e) aircraft;
(f) motor vehicles;
(g) furniture and fixtures; and
(h) office equipment.

38 The items within a class of property, plant and equipment are revalued simultaneously to avoid selective revaluation of assets and the reporting of amounts in the financial statements that are a mixture of costs and values as at different dates. However, a class of assets may be revalued on a rolling basis provided revaluation of the class of assets is completed within a short period and provided the revaluations are kept up to date.

39 If an asset's carrying amount is increased as a result of a revaluation, the increase shall be recognised in other comprehensive income and accumulated in equity under the heading of revaluation surplus. However, the increase shall be recognised in profit or loss to the extent that it reverses a revaluation decrease of the same asset previously recognised in profit or loss.

40 If an asset's carrying amount is decreased as a result of a revaluation, the decrease shall be recognised in profit or loss. However, the decrease shall be recognised in other comprehensive income to the extent of any credit balance existing in the revaluation surplus in respect of that asset. The decrease recognised in other comprehensive income reduces the amount accumulated in equity under the heading of revaluation surplus.

41 The revaluation surplus included in equity in respect of an item of property, plant and equipment may be transferred directly to retained earnings when the asset is derecognised. This may involve transferring the whole of the surplus when the asset is retired or disposed of. However, some of the surplus may be transferred as the asset is used by an entity. In such a case, the amount of the surplus transferred would be the difference between depreciation based on the revalued carrying amount of the asset and depreciation based on the asset's original cost. Transfers from revaluation surplus to retained earnings are not made through profit or loss.

42 The effects of taxes on income, if any, resulting from the revaluation of property, plant and equipment are recognised and disclosed in accordance with IAS 12 *Income Taxes*.

Depreciation

43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

44 An entity allocates the amount initially recognised in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part. For example, it may be appropriate to depreciate separately the airframe and engines of an aircraft, whether owned or subject to a finance lease. Similarly, if an entity acquires property, plant and equipment subject to an operating lease in which it is the lessor, it may be appropriate to depreciate separately amounts reflected in the cost of that item that are attributable to favourable or unfavourable lease terms relative to market terms.

45 A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

46 To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item. The remainder consists of the parts of the item that are individually not significant. If an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life of its parts.

47 An entity may choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item.

48 The depreciation charge for each period shall be recognised in profit or loss unless it is included in the carrying amount of another asset.

49 The depreciation charge for a period is usually recognised in profit or loss. However, sometimes, the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the depreciation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, the depreciation of manufacturing plant and equipment is included in the costs of conversion of inventories (see IAS 2). Similarly, depreciation of property, plant and equipment used for development activities may be included in the cost of an intangible asset recognised in accordance with IAS 38 *Intangible Assets*.

Depreciable amount and depreciation period

50 The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.

51 The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*.

52 Depreciation is recognised even if the fair value of the asset exceeds its carrying amount, as long as the asset's residual value does not exceed its carrying amount. Repair and maintenance of an asset do not negate the need to depreciate it.

53 The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

54 The residual value of an asset may increase to an amount equal to or greater than the asset's carrying amount. If it does, the asset's depreciation charge is zero unless and until its residual value subsequently decreases to an amount below the asset's carrying amount.

55 Depreciation of an asset begins when it is available for use, ie when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5 and the date that the asset is derecognised. Therefore, depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated. However, under usage methods of depreciation the depreciation charge can be zero while there is no production.

56 The future economic benefits embodied in an asset are consumed by an entity principally through its use. However, other factors, such as technical or commercial obsolescence and wear and tear while an asset remains idle, often result in the diminution of the economic benefits that might have been obtained from the asset. Consequently, all the following factors are considered in determining the useful life of an asset:

(a) expected usage of the asset. Usage is assessed by reference to the asset's

expected capacity or physical output.

(b) expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance programme, and the care and maintenance of the asset while idle.

(c) technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.

(d) legal or similar limits on the use of the asset, such as the expiry dates of related leases.

57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.

58 Land and buildings are separable assets and are accounted for separately, even when they are acquired together. With some exceptions, such as quarries and sites used for landfill, land has an unlimited useful life and therefore is not depreciated. Buildings have a limited useful life and therefore are depreciable assets. An increase in the value of the land on which a building stands does not affect the determination of the depreciable amount of the building.

59 If the cost of land includes the costs of site dismantlement, removal and restoration, that portion of the land asset is depreciated over the period of benefits obtained by incurring those costs. In some cases, the land itself may have a limited useful life, in which case it is depreciated in a manner that reflects the benefits to be derived from it.

Depreciation method

60 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.

61 The depreciation method applied to an asset shall be reviewed at least at each financial year-end and, if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method shall be changed to reflect the changed pattern. Such a change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

62 A variety of depreciation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the units of production method. Straight-line depreciation results in a constant charge over the useful life if the asset's residual value does not change. The diminishing balance method results in a decreasing charge over the useful life. The units of production method results in a charge based on the expected use or output. The entity selects the method that most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. That method is applied consistently from period to period unless there is a change in the expected pattern of consumption of those future economic benefits.

Impairment

63 To determine whether an item of property, plant and equipment is impaired, an entity applies IAS 36 *Impairment of Assets*. That Standard explains how an entity reviews the carrying amount of its assets, how it determines the recoverable amount of an asset, and when it recognises, or reverses the recognition of, an impairment loss.

64 [Deleted]

Compensation for impairment

65 Compensation from third parties for items of property, plant and equipment that were impaired, lost or given up shall be included in profit or loss when the compensation becomes receivable.

66 Impairments or losses of items of property, plant and equipment, related claims for or payments of compensation from third parties and any subsequent purchase or construction of replacement assets are separate economic events and are accounted for separately as follows:

(a) impairments of items of property, plant and equipment are recognised in accordance with IAS 36;

(b) derecognition of items of property, plant and equipment retired or disposed of is determined in accordance with this Standard;

(c) compensation from third parties for items of property, plant and equipment that were impaired, lost or given up is included in determining profit or loss when it becomes receivable; and

(d) the cost of items of property, plant and equipment restored, purchased or constructed as replacements is determined in accordance with this Standard.

Derecognition

67 The carrying amount of an item of property, plant and equipment shall be derecognised:

(a) on disposal; or

(b) when no future economic benefits are expected from its use or disposal.

68 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognised (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.

68A However, an entity that, in the course of its ordinary activities, routinely sells items of property, plant and equipment that it has held for rental to others shall transfer such assets to inventories at their carrying amount when they cease to be rented and become held for sale. The proceeds from the sale of such assets shall be recognised as revenue in accordance with IAS 18 *Revenue*. IFRS 5 does not apply when assets that are held for sale in the ordinary course of business are transferred to inventories.

69 The disposal of an item of property, plant and equipment may occur in a variety of ways (eg by sale, by entering into a finance lease or by donation). In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognising revenue from the sale of goods. IAS 17 applies to disposal by a sale and leaseback.

70 If, under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of a replacement for part of the item, then it derecognises the carrying amount of the replaced part regardless of whether the replaced part had been depreciated separately. If it is not practicable for an entity to determine the carrying amount of the replaced part, it may use the cost of the replacement as an indication of what the cost of the replaced part was at the time it was acquired or constructed.

71 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

72 The consideration receivable on disposal of an item of property, plant and equipment is recognised initially at its fair value. If payment for the item is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue in accordance with IAS 18 reflecting the effective yield on the receivable.

Disclosure

73 The financial statements shall disclose, for each class of property, plant and equipment:

(a) the measurement bases used for determining the gross carrying amount;

(b) the depreciation methods used;

(c) the useful lives or the depreciation rates used;

(d) the gross carrying amount and the accumulated depreciation (aggregated with accumulated impairment losses) at the beginning and end of the period; and

(e) a reconciliation of the carrying amount at the beginning and end of the period showing:

(i) additions;

(ii) assets classified as held for sale or included in a disposal group classified as held for sale in accordance with IFRS 5 and other disposals;

(iii) acquisitions through business combinations;

(iv) increases or decreases resulting from revaluations under paragraphs 31, 39 and 40 and from impairment losses recognised or reversed in other comprehensive income in accordance with IAS 36;

(v) impairment losses recognised in profit or loss in accordance with IAS 36;

(vi) impairment losses reversed in profit or loss in accordance with IAS 36;

(vii) depreciation;

(viii) the net exchange differences arising on the translation of the financial statements from the functional currency into a different presentation currency, including the translation of a foreign operation into the presentation currency of the reporting entity; and

(ix) other changes.

74 The financial statements shall also disclose:

(a) the existence and amounts of restrictions on title, and property, plant and equipment pledged as security for liabilities;

(b) the amount of expenditures recognised in the carrying amount of an item of property, plant and equipment in the course of its construction;

(c) the amount of contractual commitments for the acquisition of property, plant and equipment; and

(d) if it is not disclosed separately in the statement of comprehensive income, the amount of compensation from third parties for items of property, plant and equipment that were impaired, lost or given up that is included in profit or loss.

75 Selection of the depreciation method and estimation of the useful life of assets are matters of judgement. Therefore, disclosure of the methods adopted and the estimated useful lives or depreciation rates provides users of financial statements with information that allows them to review the policies selected by management and enables comparisons to be made with other entities. For similar reasons, it is necessary to disclose:

(a) depreciation, whether recognised in profit or loss or as a part of the cost of other assets, during a period; and

(b) accumulated depreciation at the end of the period.

76 In accordance with IAS 8 an entity discloses the nature and effect of a change in an accounting estimate that has an effect in the current period or is expected to have an effect in subsequent periods. For property, plant and equipment, such disclosure may arise from changes in estimates with respect to:

(a) residual values;

(b) the estimated costs of dismantling, removing or restoring items of property, plant and equipment;

(c) useful lives; and

(d) depreciation methods.

77 If items of property, plant and equipment are stated at revalued amounts, the following shall be disclosed in addition to the disclosures required by IFRS 13:

(a) the effective date of the revaluation;

(b) whether an independent valuer was involved;

(c) [deleted]

(d) [deleted]

(e) for each revalued class of property, plant and equipment, the carrying amount that would have been recognised had the assets been carried under the cost model; and

(f) the revaluation surplus, indicating the change for the period and any restrictions on the distribution of the balance to shareholders.

78 In accordance with IAS 36 an entity discloses information on impaired property, plant and equipment in addition to the information required by paragraph 73(e)(iv)–(vi).

79 Users of financial statements may also find the following information relevant to their needs:

(a) the carrying amount of temporarily idle property, plant and equipment;

(b) the gross carrying amount of any fully depreciated property, plant and equipment that is still in use;

(c) the carrying amount of property, plant and equipment retired from active use and not classified as held for sale in accordance with IFRS 5; and

(d) when the cost model is used, the fair value of property, plant and equipment when this is materially different from the carrying amount.

Therefore, entities are encouraged to disclose these amounts.

Transitional provisions

80 The requirements of paragraphs 24–26 regarding the initial measurement of an item of property, plant and equipment acquired in an exchange of assets transaction shall be applied prospectively only to future transactions.

Effective date

81 An entity shall apply this Standard for annual periods beginning on or after 1 January 2005. Earlier application is encouraged. If an entity applies this Standard for a period beginning before 1 January 2005, it shall disclose that fact.

81A An entity shall apply the amendments in paragraph 3 for annual periods beginning on or after 1 January 2006. If an entity applies IFRS 6 for an earlier period, those amendments shall be applied for that earlier period.

81B IAS 1 *Presentation of Financial Statements* (as revised in 2007) amended the terminology used throughout IFRSs. In addition it amended paragraphs 39, 40 and 73 (e)(iv). An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. If an entity applies IAS 1 (revised 2007) for an earlier period, the amendments shall be applied for that earlier period.

81C IFRS 3 *Business Combinations* (as revised in 2008) amended paragraph 44. An entity shall apply that amendment for annual periods beginning on or after 1 July 2009. If an entity applies IFRS 3 (revised 2008) for an earlier period, the amendment shall also be applied for that earlier period.

81D Paragraphs 6 and 69 were amended and paragraph 68A was added by *Improvements to IFRSs* issued in May 2008. An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. Earlier application is permitted. If an entity applies the amendments for an earlier period it shall disclose that fact and at the same time apply the related amendments to IAS 7 *Statement of Cash Flows*.

81E Paragraph 5 was amended by *Improvements to IFRSs* issued in May 2008. An entity shall apply that amendment prospectively for annual periods beginning on or after 1 January 2009. Earlier application is permitted if an entity also applies the amendments to paragraphs 8, 9, 22, 48, 53, 53A, 53B, 54, 57 and 85B of IAS 40 at the same time. If

an entity applies the amendment for an earlier period it shall disclose that fact.

81F IFRS 13, issued in May 2011, amended the definition of fair value in paragraph 6, amended paragraphs 26, 35 and 77 and deleted paragraphs 32 and 33. An entity shall apply those amendments when it applies IFRS 13.

81G *Annual Improvements 2009–2011 Cycle*, issued in May 2012, amended paragraph 8. An entity shall apply that amendment retrospectively in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* for annual periods beginning on or after 1 January 2013. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Withdrawal of other pronouncements

82 This Standard supersedes IAS 16 *Property, Plant and Equipment* (revised in 1998).

83 This Standard supersedes the following Interpretations:

(a) SIC-6 *Costs of Modifying Existing Software*;

(b) SIC-14 *Property, Plant and Equipment — Compensation for the Impairment or Loss of Items*; and

(c) SIC-23 *Property, Plant and Equipment — Major Inspection or Overhaul Costs*.

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CW-YECL-32

Reference: Depreciation, YECL Application, Attachment 1, page II-23.

Under Account 473.00 – Distribution Poles, Towers and Fixtures, Mr. Kennedy indicates that Distribution Poles, Towers, and Fixtures are analysed together as one group.

Request:

(a) Please fully describe the assets included as fixtures.

(b) Please confirm that, under IFRS, assets are to be grouped or componentized into groups that have similar lives. If not confirmed, please fully explain.

(c) Please provide all analysis conducted that demonstrates that each of Distribution Poles, Towers, and Fixtures have similar lives.

(d) Please provide the original cost of each of Distribution Poles, Towers, and Fixtures forecast for 2013, 2014, and 2015.

Response:

(a) Fixtures included in Account 47300 include the following:

- Anchors, head arm and other guys, including any guard, guy clamps, strain insulators, pole plates, etc.;
- Brackets;
- Crossarms and braces;
- Extension arms;
- Foundations;
- Ground Rods and Clamps;
- Guards;
- Insulator pins and suspension bolts;
- Poles steps;
- Racks complete with insulators;
- Reinforcing and stubbing;

- Settings;
- Shaving;
- Paint;
- Roofing;
- Stenciling;
- Tagging;
- Transformer racks and platforms;
- Other fixtures.

(b) Confirmed.

(c) It was determined during early discussions that the operational practices of Yukon Electrical would result in the life estimation to be very similar for Distribution Poles, Towers and Fixtures. Historically, the Poles, Towers and Fixtures account has contained the investment related to a fully dressed pole and the cost and effort associated with sub-componentizing the investment into poles and fixtures would be extensive and the cost would not warrant the reasonably expected small change in life estimates. It was noted that in most circumstances the retirement of poles also include the retirement of all fixtures attached to the poles, and furthermore, most fixtures are not retired until the pole is removed from service.

Gannett Fleming also notes that most regulated electric distribution utilities across Canada do not componentize the fixtures on a pole separately from the investment in the pole.

Yukon Electrical does not have any steel towers within its system, and only a limited number of wood towers. The expectation is that the limited number of wood towers would have a similar life characteristic as wood poles. Therefore the componentization of the limited investment in wood towers into a separate account is not warranted.

(d) As shown in Section 7, Schedules 7.2-7.4, the investment in Account 47300 is $34,533,000, $37,092,000, and $39,937,000 for 2013, 2014 and 2015 respectively. Yukon Electrical does not maintain Account 47300 to the level requested.

CW-YECL-33

Reference: Depreciation, YECL Application, page 7-1

On line 10-14, YECL states:

10 .....For this
11 depreciation study, Yukon Electrical has incorporated the usage of a life span analysis
12 (similar to hydro generation) for each of its diesel generation locations. This will allow
13 for more accurate depreciation rates for diesel generation facilities. The depreciation
14 methods and results are presented in the study.

The City requires information to understand the impact of the change.

Request:

(a) Please provide a full and complete explanation of the difference between the life span analysis and the previous depreciation method for diesel assets.

(b) Please fully explain how the life span analysis produces more accurate depreciation rates.

(c) Please provide an analysis that clearly quantifies the impact of the change on depreciation rates and expense.

Response:

(a) Please refer to the response to information request YUB-YECL-81(b).

(b) Please refer to the response to information request YUB-YECL-81(b).

(c) Please refer to CW-YECL-33 Attachments 1 and 2, being schedules of depreciation rates calculated in the same manner as Schedules 1A and 2A of the Gannett Fleming report, but with the Life Span Impacts removed. In total, the inclusion of the Life Span approach has a less than $50,000[1] impact on the depreciation expense applied to the recovery of original cost.

[1] Difference between the filed Schedules 1A and 2A (Section 7, Attachment 1, pages 53 and 56, Annual Provision for True-Ups) and Schedules 1A and 2A referenced in this information response.

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
GENERATION							
HYDRO GENERATION (LIFE SPAN OF 2052)							
422.00	HYDRO STRUCTURES	72- R2	(10)	215,286	55,887	4,066	1.89
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	(10)	1,875,073	217,466	22,936	1.22
425.00	HYDRO GENERATORS	85- R3	(10)	1,458,435	114,857	21,767	1.49
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	(10)	105,192	53,085	2,665	2.53
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	(10)	68,657	21,393	2,897	4.22
TOTAL HYDRO PLANT				**3,722,643**	**462,688**	**54,331**	
DIESEL GENERATION							
BEAVER CREEK (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,488	24,449	987	2.63
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	92,859	48,830	3,263	3.51
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	535,779	404,185	21,611	4.03
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	173,365	57,856	5,293	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	48,603	8,070	1,358	2.79
TOTAL BEAVER CREEK				**888,094**	**543,390**	**32,512**	
CARMACKS (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	167,739	48,069	5,160	3.08
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	40,394	30,085	1,395	3.45
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	419,543	340,161	16,443	3.92
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	101,158	34,682	3,102	3.07
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	7,366	526	212	2.88
TOTAL CARMACKS				**736,201**	**453,523**	**26,312**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DESTRUCTION BAY (LIFE SPAN OF 2023)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	42,282	31,410	1,054	2.49
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	105,478	48,762	3,761	3.57
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	488,076	137,467	21,760	4.46
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	284,627	110,212	8,557	3.01
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	28,048	9,297	750	2.67
TOTAL DESTRUCTION BAY				**948,512**	**337,148**	**35,882**	
HAINES JUNCTION (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	608,472	124,969	19,354	3.18
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	619,132	298,626	22,049	3.56
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	60,097	41,010	2,538	4.22
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	94,952	47,492	2,677	2.82
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	2,454	1,480	58	2.36
TOTAL HAINES JUNCTION				**1,385,107**	**513,577**	**46,676**	
OLD CROW (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	187,900	112,056	5,101	2.71
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	215,087	99,570	7,563	3.52
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	1,223,713	582,440	54,655	4.47
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	119,365	68,323	3,379	2.83
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	171,496	66,372	4,541	2.65
TOTAL OLD CROW				**1,917,561**	**928,761**	**75,239**	
PELLY CROSSING (LIFE SPAN OF 2033)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	48,892	36,350	1,234	2.52
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	129,302	109,763	3,923	3.03
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	474,056	329,947	19,657	4.15
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	431,735	151,302	13,158	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	61,485	17,984	1,668	2.71
TOTAL PELLY CROSSING				**1,145,469**	**645,346**	**39,640**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
ROSS RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	171,221	62,610	5,094	2.98
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	85,126	39,551	3,056	3.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	189,753	161,805	7,158	3.77
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	124,872	48,576	3,768	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	9,639	1,747	267	2.77
TOTAL ROSS RIVER				**580,611**	**314,289**	**19,343**	
STEWART CROSSING (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	247,966	69,787	7,636	3.08
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	65,107	17,905	2,331	3.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	45,677	27,331	1,842	4.03
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	70,425	26,610	2,126	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	84,682	6,880	2,439	2.88
TOTAL STEWART CROSSING				**513,857**	**148,513**	**16,374**	
SWIFT RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	22,503	10,866	638	2.84
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	63,430	45,174	2,194	3.46
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	241,047	108,696	10,643	4.42
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	93,560	31,048	2,877	3.08
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	11,924	3,171	326	2.73
TOTAL SWIFT RIVER				**432,465**	**198,955**	**16,678**	
TESLIN (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,986	11,428	1,205	3.17
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	99,863	27,143	3,619	3.62
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	762,034	576,875	31,182	4.09
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	54,417	25,006	1,611	2.96
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	69,778	9,088	1,966	2.82
TOTAL TESLIN				**1,024,077**	**649,540**	**39,583**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
WATSON LAKE (LIFE SPAN OF 2113)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	359,393	224,332	9,727	2.71
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	747,818	129,740	27,011	3.61
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	2,169,195	1,450,577	87,925	4.05
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	578,189	305,256	16,449	2.84
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	258,430	61,919	7,095	2.75
TOTAL WATSON LAKE				**4,113,025**	**2,171,824**	**148,207**	
TOTAL DIESEL PLANT				**13,684,978**	**6,904,866**	**496,446**	
MOBILE							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	10,662	9,690	239	2.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	25,562	20,399	868	3.40
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	568,500	333,611	23,635	4.16
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	87,652	40,799	2,555	2.91
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	92,170	12,008	2,603	2.82
TOTAL MOBILE				**784,546**	**416,507**	**29,900**	
TOTAL GENERATION				**18,192,167**	**7,784,061**	**580,677**	
SUBSTATION PLANT							
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	(10)	1,384,421	689,303	31,326	2.26
TOTAL SUBSTATION PLANT				**1,384,421**	**689,303**	**31,326**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	75- R3	0	1,267,608	151,638	19,155	1.51
473.00	POLES, TOWERS AND FIXTURES	45- R3	(75)	30,231,546	15,702,296	1,271,960	4.21
474.00	OVERHEAD CONDUCTOR	45- R4	(80)	20,514,612	10,498,681	855,625	4.17
474.10	OVERHEAD SERVICES	45- R3	(10)	2,849,453	1,125,671	73,754	2.59
475.00	UNDERGROUND CONDUIT	45- R3	(50)	20,982,589	9,111,686	759,512	3.62
475.10	UNDERGROUND SERVICES	40- R4	(10)	2,953,077	1,016,443	84,924	2.88
476.10	METERS	15- L0	0	1,683,985	682,328	134,650	8.00
476.30	AMR - METERS	15- R2.5	0	67,646	14,259	5,175	7.65
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	(10)	3,131,073	1,765,608	86,967	2.78
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	(10)	9,147,522	4,196,129	347,924	3.80
478.20	SENTINEL LIGHTS	23- R2	0	284,738	246,947	8,784	3.08
479.10	LINE TRANSFORMERS	45- R3	(10)	24,427,769	7,365,548	649,018	2.66
TOTAL DISTRIBUTION PLANT				**117,541,619**	**51,877,234**	**4,297,448**	
GENERAL PLANT							
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	0	3,459,315	1,660,879	91,701	2.65
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	0	172,793	62,511	10,448	6.05
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	0	47,367	10,448	8,929	18.85
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	25	2,561,147	964,510	157,467	6.15
485.00	TOOLS AND INSTRUMENTS	15- SQ	0	719,184	273,558	46,712	6.50
486.00	COMMUNICATION EQUIPMENT	15- SQ	0	872,842	422,551	49,726	5.70
488.20	HOUSES	40- R3	(10)	473,256	167,636	13,991	2.96
TOTAL GENERAL PLANT				**8,305,904**	**3,562,093**	**378,974**	
TOTAL UTILITY PLANT IN SERVICE				**145,424,111**	**63,912,691**	**5,288,425**	
(*) Interim Survivor Curve					47,322,767	3,941,917	
					16,589,924	1,346,508	
					63,912,691	5,288,425	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
GENERATION						
HYDRO GENERATION (LIFE SPAN REMOVED)						
422.00	HYDRO STRUCTURES	72- R2	215,286	50,806	3,696	1.72
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	1,875,073	197,696	20,851	1.11
425.00	HYDRO GENERATORS	85- R3	1,458,435	104,415	19,788	1.36
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	105,192	48,259	2,423	2.30
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	68,657	19,448	2,634	3.84
TOTAL HYDRO PLANT			**3,722,643**	**420,625**	**49,392**	
DIESEL GENERATION						
BEAVER CREEK (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	37,488	22,226	897	2.39
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	92,859	40,692	2,719	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	535,779	367,441	19,646	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	173,365	57,856	5,293	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	48,603	8,070	1,358	2.79
TOTAL BEAVER CREEK			**888,094**	**496,285**	**29,914**	
CARMACKS (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	167,739	43,699	4,691	2.80
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	40,394	25,071	1,163	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	419,543	309,237	14,948	3.56
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	101,158	34,682	3,102	3.07
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	7,366	526	212	2.88
TOTAL CARMACKS			**736,201**	**413,215**	**24,116**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
DESTRUCTION BAY (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	42,282	28,555	958	2.27
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	105,478	40,635	3,134	2.97
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	488,076	124,970	19,782	4.05
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	284,627	110,212	8,557	3.01
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	28,048	9,297	750	2.67
TOTAL DESTRUCTION BAY			**948,512**	**313,669**	**33,181**	
HAINES JUNCTION (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	608,472	113,608	17,595	2.89
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	619,132	248,855	18,374	2.97
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	60,097	37,282	2,307	3.84
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	94,952	47,492	2,677	2.82
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	2,454	1,480	58	2.36
TOTAL HAINES JUNCTION			**1,385,107**	**448,717**	**41,011**	
OLD CROW (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	187,900	101,869	4,637	2.47
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	215,087	82,975	6,303	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	1,223,713	529,491	49,686	4.06
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	119,365	68,323	3,379	2.83
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	171,496	66,372	4,541	2.65
TOTAL OLD CROW			**1,917,561**	**849,030**	**68,546**	
PELLY CROSSING (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	48,892	33,045	1,122	2.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	129,302	91,469	3,269	2.53
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	474,056	299,952	17,870	3.77
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	431,735	151,302	13,158	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	61,485	17,984	1,668	2.71
TOTAL PELLY CROSSING			**1,145,469**	**593,752**	**37,087**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
ROSS RIVER (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	171,221	56,918	4,631	2.70
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	85,126	32,959	2,547	2.99
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	189,753	147,095	6,507	3.43
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	124,872	48,576	3,768	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	9,639	1,747	267	2.77
TOTAL ROSS RIVER			**580,611**	**287,296**	**17,720**	
STEWART CROSSING (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	247,966	63,443	6,942	2.80
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	65,107	14,921	1,943	2.98
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	45,677	24,846	1,675	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	70,425	26,610	2,126	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	84,682	6,880	2,439	2.88
TOTAL STEWART CROSSING			**513,857**	**136,700**	**15,124**	
SWIFT RIVER (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	22,503	9,878	580	2.58
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	63,430	37,645	1,828	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	241,047	98,815	9,675	4.01
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	93,560	31,048	2,877	3.08
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	11,924	3,171	326	2.73
TOTAL SWIFT RIVER			**432,465**	**180,557**	**15,287**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
TESLIN (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	37,986	10,389	1,095	2.88
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	99,863	22,619	3,016	3.02
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	762,034	524,432	28,347	3.72
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	54,417	25,006	1,611	2.96
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	69,778	9,088	1,966	2.82
TOTAL TESLIN			**1,024,077**	**591,534**	**36,036**	
WATSON LAKE (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	359,393	203,938	8,843	2.46
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	747,818	108,117	22,509	3.01
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	2,169,195	1,318,706	79,932	3.68
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	578,189	305,256	16,449	2.84
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	258,430	61,919	7,095	2.75
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**134,828**	
TOTAL DIESEL PLANT			**13,684,978**	**6,308,691**	**452,848**	
MOBILE						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	10,662	8,809	217	2.04
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	25,562	16,999	723	2.83
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	568,500	303,283	21,486	3.78
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	87,652	40,799	2,555	2.91
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	92,170	12,008	2,603	2.82
TOTAL MOBILE			**784,546**	**381,898**	**27,585**	
TOTAL GENERATION			**18,192,167**	**7,111,214**	**529,825**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
SUBSTATION PLANT						
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	1,384,421	626,639	28,478	2.06
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**28,478**	
DISTRIBUTION PLANT						
471.00	LAND RIGHTS	75- R3	1,267,608	151,638	19,155	1.51
473.00	POLES, TOWERS AND FIXTURES	45- R3	30,231,546	8,972,741	726,834	2.40
474.00	OVERHEAD CONDUCTOR	45- R4	20,514,612	5,832,601	475,347	2.32
474.10	OVERHEAD SERVICES	45- R3	2,849,453	1,023,337	67,049	2.35
475.00	UNDERGROUND CONDUIT	45- R3	20,982,589	6,074,457	506,341	2.41
475.10	UNDERGROUND SERVICES	40- R4	2,953,077	924,039	77,204	2.61
476.10	METERS	15- L0	1,683,985	682,328	134,650	8.00
476.30	AMR - METERS	15- R2.5	67,646	14,259	5,175	7.65
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	3,131,073	1,605,098	79,061	2.53
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	9,147,522	3,814,663	316,295	3.46
478.20	SENTINEL LIGHTS	23- R2	284,738	246,947	8,784	3.08
479.10	LINE TRANSFORMERS	45- R3	24,427,769	6,695,953	590,016	2.42
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**3,005,911**	
GENERAL PLANT						
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	3,459,315	1,660,879	91,701	2.65
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	172,793	62,511	10,448	6.05
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	47,367	10,448	8,929	18.85
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	2,561,147	964,510	157,467	6.15
485.00	TOOLS AND INSTRUMENTS	15- SQ	719,184	273,558	46,712	6.50
486.00	COMMUNICATION EQUIPMENT	15- SQ	872,842	422,551	49,726	5.70
488.20	HOUSES	40- R3	473,256	152,396	12,719	2.69
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**377,702**	
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,322,767**	**3,941,917**	

(*) Interim Survivor Curve

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
GENERATION							
HYDRO PLANT (LIFE SPAN REMOVED)							
422.00	HYDRO STRUCTURES	72- R2	(10)	215,286	5,081	370	0.17
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	(10)	1,875,073	19,770	2,085	0.11
425.00	HYDRO GENERATORS	85- R3	(10)	1,458,435	10,442	1,979	0.14
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	(10)	105,192	4,826	242	0.23
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	(10)	68,657	1,945	263	0.38
TOTAL HYDRO PLANT				**3,722,643**	**42,063**	**4,939**	
PRODUCTION DIESEL PLANT							
BEAVER CREEK (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,488	2,223	90	0.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	92,859	8,138	544	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	535,779	36,744	1,965	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	173,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	48,603	-	-	-
TOTAL BEAVER CREEK				**888,094**	**47,105**	**2,598**	
CARMACKS (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	167,739	4,370	469	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	40,394	5,014	233	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	419,543	30,924	1,495	0.36
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	101,158	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	7,366	-	-	-
TOTAL CARMACKS				**736,201**	**40,308**	**2,196**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DESTRUCTION BAY (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	42,282	2,855	96	0.23
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	105,478	8,127	627	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	488,076	12,497	1,978	0.41
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	284,627	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	28,048	-	-	-
TOTAL DESTRUCTION BAY				**948,512**	**23,479**	**2,701**	
HAINES JUNCTION (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	608,472	11,361	1,759	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	619,132	49,771	3,675	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	60,097	3,728	231	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	94,952	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	2,454	-	-	-
TOTAL HAINES JUNCTION				**1,385,107**	**64,860**	**5,665**	
OLD CROW (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	187,900	10,187	464	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	215,087	16,595	1,261	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	1,223,713	52,949	4,969	0.41
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	119,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	171,496	-	-	-
TOTAL OLD CROW				**1,917,561**	**79,731**	**6,693**	
PELLY CROSSING (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	48,892	3,305	112	0.23
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	129,302	18,294	654	0.51
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	474,056	29,995	1,787	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	431,735	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	61,485	-	-	-
TOTAL PELLY CROSSING				**1,145,469**	**51,594**	**2,553**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
ROSS RIVER (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	171,221	5,692	463	0.27
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	85,126	6,592	509	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	189,753	14,710	651	0.34
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	124,872	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	9,639	-	-	-
TOTAL ROSS RIVER				**580,611**	**26,993**	**1,623**	
STEWART CROSSING (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	247,966	6,344	694	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	65,107	2,984	389	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	45,677	2,485	167	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	70,425	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	84,682	-	-	-
TOTAL STEWART CROSSING				**513,857**	**11,813**	**1,250**	
SWIFT RIVER (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	22,503	988	58	0.26
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	63,430	7,529	366	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	241,047	9,881	968	0.40
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	93,560	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	11,924	-	-	-
TOTAL SWIFT RIVER				**432,465**	**18,398**	**1,391**	
TESLIN(LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,986	1,039	110	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	99,863	4,524	603	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	762,034	52,443	2,835	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	54,417	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	69,778	-	-	-
TOTAL TESLIN				**1,024,077**	**58,006**	**3,547**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
WATSON LAKE (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	359,393	20,394	884	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	747,818	21,623	4,502	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	2,169,195	131,871	7,993	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	578,189	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	258,430	-	-	-
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**13,379**	
TOTAL DIESEL PLANT				**13,684,978**	**596,175**	**43,598**	
MOBILE							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	10,662	881	22	0.20
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	25,562	3,400	145	0.57
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	568,500	30,328	2,149	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	87,652	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	92,170	-	-	-
TOTAL MOBILE				**784,546**	**34,609**	**2,315**	
TOTAL GENERATION				**18,192,167**	**672,847**	**50,852**	
SUBSTATION PLANT							
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	(10)	1,384,421	62,664	2,848	0.21
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**2,848**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	75- R3	0	1,267,608	-	-	-
473.00	POLES, TOWERS AND FIXTURES	45- R3	(75)	30,231,546	6,729,555	545,126	1.80
474.00	OVERHEAD CONDUCTOR	45- R4	(80)	20,514,612	4,666,080	380,278	1.85
474.10	OVERHEAD SERVICES	45- R3	(10)	2,849,453	102,334	6,705	0.24
475.00	UNDERGROUND CONDUIT	45- R3	(50)	20,982,589	3,037,229	253,171	1.21
475.10	UNDERGROUND SERVICES	40- R4	(10)	2,953,077	92,404	7,720	0.26
476.10	METERS	15- L0	0	1,683,985	-	-	-
476.30	AMR - METERS	15- R2.5	0	67,646	-	-	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	(10)	3,131,073	160,510	7,906	0.25
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	(10)	9,147,522	381,466	31,629	0.35
478.20	SENTINEL LIGHTS	23- R2	0	284,738	-	-	-
479.10	LINE TRANSFORMERS	45- R3	(10)	24,427,769	669,595	59,002	0.24
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**1,291,536**	
GENERAL PLANT							
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	0	3,459,315	-	-	-
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	0	172,793	-	-	-
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	0	47,367	-	-	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	25	2,561,147	-	-	-
485.00	TOOLS AND INSTRUMENTS	15- SQ	0	719,184	-	-	-
486.00	COMMUNICATION EQUIPMENT	15- SQ	0	872,842	-	-	-
488.20	HOUSES	40- R3	(10)	473,256	15,240	1,272	0.27
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**1,272**	
TOTAL UTILITY PLANT IN SERVICE				**145,424,111**	**16,589,924**	**1,346,508**	

(*) Interim Survivor Curve

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION									
HYDRO PLANT (LIFE SPAN REMOVED)									
422.00	HYDRO STRUCTURES	0-ND	(10)	215,286	55,887	124,005	(68,118)	64.1	(1,063)
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	(10)	1,875,073	217,466	666,411	(448,945)	97.7	(4,595)
425.00	HYDRO GENERATORS	103-R3	(10)	1,458,435	114,857	317,214	(202,357)	81.9	(2,471)
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	(10)	105,192	53,085	100,267	(47,182)	34.3	(1,376)
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	(10)	68,657	21,393	40,256	(18,863)	27.7	(681)
TOTAL HYDRO PLANT				**3,722,643**	**462,688**	**1,248,153**	**(785,465)**		**(10,185)**
PRODUCTION DIESEL PLANT									
BEAVER CREEK(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,488	24,449	23,208	1,241	19.2	65
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	92,859	48,830	51,507	(2,677)	22.0	(122)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	535,779	404,185	370,768	33,417	9.6	3,481
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	173,365	57,856	71,106	(13,250)	26.1	(508)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	48,603	8,070	11,347	(3,277)	34.9	(94)
TOTAL BEAVER CREEK				**888,094**	**543,390**	**527,936**	**15,454**		**2,822**
CARMACKS (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	167,739	48,069	46,129	1,940	31.7	61
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	40,394	30,085	31,735	(1,650)	14.4	(115)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	419,543	340,161	312,037	28,124	8.3	3,388
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	101,158	34,682	42,594	(7,912)	24.7	(320)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	7,366	526	741	(215)	39.0	(6)
TOTAL CARMACKS				**736,201**	**453,523**	**433,236**	**20,287**		**3,009**
DESTRUCTION BAY(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	42,282	31,410	32,563	(1,153)	17.2	(67)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	105,478	48,762	69,050	(20,288)	23.3	(871)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	488,076	137,467	141,304	(3,837)	21.1	(182)
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	284,627	110,212	174,968	(64,756)	27.7	(2,338)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	28,048	9,297	18,250	(8,953)	34.7	(258)
TOTAL DESTRUCTION BAY				**948,512**	**337,148**	**436,135**	**(98,987)**		**(3,715)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	608,472	124,969	120,535	4,434	34.8	127
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	619,132	298,626	315,076	(16,450)	21.9	(751)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	60,097	41,010	37,619	3,391	11.2	303
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	94,952	47,492	58,328	(10,836)	25.4	(427)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	2,454	1,480	2,053	(573)	36.5	(16)
TOTAL HAINES JUNCTION				**1,385,107**	**513,577**	**533,611**	**(20,034)**		**(763)**
OLD CROW (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	187,900	112,056	106,381	5,675	21.2	268
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	215,087	99,570	105,029	(5,459)	24.1	(227)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	1,223,713	582,440	535,342	47,098	15.7	3,000
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	119,365	68,323	83,910	(15,587)	18.9	(825)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	171,496	66,372	92,168	(25,796)	27.3	(945)
TOTAL OLD CROW				**1,917,561**	**928,761**	**922,830**	**5,931**		**1,271**
PELLY CROSSING (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	48,892	36,350	35,274	1,076	15.9	68
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	129,302	109,763	117,576	(7,813)	27.4	(285)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	474,056	329,947	302,837	27,110	10.9	2,487
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	431,735	151,302	201,570	(50,268)	25.3	(1,987)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	61,485	17,984	27,874	(9,890)	33.4	(296)
TOTAL PELLY CROSSING				**1,145,469**	**645,346**	**685,131**	**(39,785)**		**(13)**
ROSS RIVER (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	171,221	62,610	59,849	2,761	29.4	94
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	85,126	39,551	41,720	(2,169)	22.2	(98)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	189,753	161,805	148,427	13,378	7.3	1,833
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	124,872	48,576	59,658	(11,082)	23.5	(472)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	9,639	1,747	2,459	(712)	35.5	(20)
TOTAL ROSS RIVER				**580,611**	**314,289**	**312,113**	**2,176**		**1,337**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	247,966	69,787	67,028	2,759	32.0	86
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	65,107	17,905	18,651	(746)	28.6	(26)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	45,677	27,331	22,882	4,449	10.9	408
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	70,425	26,610	32,681	(6,071)	24.9	(244)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	84,682	6,880	9,677	(2,797)	38.1	(73)
TOTAL STEWART CROSSING				**513,857**	**148,513**	**150,919**	**(2,406)**		**151**
SWIFT RIVER (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	22,503	10,866	10,333	533	25.6	21
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	63,430	45,174	47,651	(2,477)	15.7	(158)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	241,047	108,696	100,060	8,636	16.3	530
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	93,560	31,048	38,140	(7,092)	25.1	(283)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	11,924	3,171	4,419	(1,248)	31.3	(40)
TOTAL SWIFT RIVER				**432,465**	**198,955**	**200,603**	**(1,648)**		**70**
TESLIN (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,986	11,428	10,886	542	31.2	17
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	99,863	27,143	28,631	(1,488)	27.5	(54)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	762,034	576,875	529,180	47,695	9.6	4,968
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	54,417	25,006	30,711	(5,705)	21.5	(265)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	69,778	9,088	12,886	(3,798)	35.6	(107)
TOTAL TESLIN				**1,024,077**	**649,540**	**612,294**	**37,246**		**4,559**
WATSON LAKE(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	359,393	224,332	212,703	11,629	20.1	579
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	747,818	129,740	136,854	(7,114)	30.6	(232)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	2,169,195	1,450,577	1,329,304	121,273	11.3	10,732
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	578,189	305,256	374,897	(69,641)	22.3	(3,123)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	258,430	61,919	85,778	(23,859)	33.8	(706)
TOTAL WATSON LAKE				**4,113,025**	**2,171,824**	**2,139,535**	**32,289**		**7,249**
TOTAL PRODUCTION DIESEL PLANT				**13,684,978**	**6,904,866**	**6,954,344**	**(49,478)**	**-**	**15,979**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	10,662	9,690	9,187	503	9.3	54
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	25,562	20,399	21,517	(1,118)	12.8	(87)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	568,500	333,611	304,470	29,141	13.1	2,225
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	87,652	40,799	50,120	(9,321)	23.1	(404)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	92,170	12,008	16,636	(4,628)	35.5	(130)
TOTAL MOBILE				**784,546**	**416,507**	**401,930**	**14,577**		**1,657**
TOTAL GENERATION				**18,192,167**	**7,784,061**	**8,604,427**	**(820,366)**		**7,451**
SUBSTATION PLANT									
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	(10)	1,384,421	689,303	851,143	(161,840)	31.0	(5,221)
TOTAL SUBSTATION PLANT				1,384,421	689,303	851,143	(161,840)		(5,221)
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	0	0	1,267,608	151,638	151,342	296	67.3	4
473.00	POLES, TOWERS AND FIXTURES	75-R3	(75)	30,231,546	15,702,296	15,172,666	529,630	33.4	15,857
474.00	OVERHEAD CONDUCTOR	45-R3	(80)	20,514,612	10,498,681	9,327,713	1,170,968	32.3	36,253
474.10	OVERHEAD SERVICES	45-R4	(10)	2,849,453	1,125,671	1,340,123	(214,452)	33.4	(6,421)
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	9,111,686	5,533,568	3,578,118	32.6	109,758
475.10	UNDERGROUND SERVICES	45-R3	(10)	2,953,077	1,016,443	1,052,955	(36,512)	28.5	(1,281)
476.10	METERS	40-R4	0	1,683,985	682,328	68,871	613,457	10.6	57,873
476.30	AMR - METERS	15-L0	0	67,646	14,259	-	14,259	12.3	1,159
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	(10)	3,131,073	1,765,608	1,821,709	(56,101)	21.5	(2,609)
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	(10)	9,147,522	4,196,129	4,907,554	(711,425)	21.1	(33,717)
478.20	SENTINEL LIGHTS	30-R3	0	284,738	246,947	213,445	33,502	4.0	8,376
479.10	LINE TRANSFORMERS	23-R2	(10)	24,427,769	7,365,548	10,107,860	(2,742,312)	37.0	(74,117)
TOTAL DISTRIBUTION PLANT				117,541,619	51,877,234	49,697,805	2,179,429		111,136
GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	0	0	3,459,315	1,660,879	1,891,893	(231,014)	23.9	(9,666)
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	0	172,793	62,511	13,162	49,349	5.5	8,973
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	0	47,367	10,448	(11,313)	21,761	3.4	6,400
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	25	2,561,147	964,510	1,284,514	(320,004)	10.0	(32,000)
485.00	TOOLS AND INSTRUMENTS	12-L0	0	719,184	273,558	239,209	34,349	8.7	3,948
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	422,551	385,392	37,159	7.8	4,764
488.20	HOUSES	15-SQ	(10)	473,256	167,636	639,815	(472,179)	21.8	(21,660)
TOTAL GENERAL PLANT				8,305,904	3,562,093	4,442,674	(880,581)		(39,241)
TOTAL UTILITY PLANT IN SERVICE				145,424,111	63,912,691	63,596,048	316,643		74,125
					47,322,767	59,200,897	-11,878,130		-395,883
					16,589,924	4,395,151	12,194,773		470,009
					63,912,691	63,596,048	316,643		74,125

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION								
HYDRO PLANT (LIFE SPAN REMOVED)								
422.00	HYDRO STRUCTURES	0-ND	215,286	50,806	123,192	(72,386)	64.1	(1,129)
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	1,875,073	197,696	662,044	(464,347)	97.7	(4,753)
425.00	HYDRO GENERATORS	103-R3	1,458,435	104,415	315,135	(210,720)	81.9	(2,573)
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	105,192	48,259	99,610	(51,351)	34.3	(1,497)
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	68,657	19,448	39,992	(20,544)	27.7	(742)
TOTAL HYDRO PLANT			**3,722,643**	**420,625**	**1,239,974**	**(819,348)**		**(10,694)**
PRODUCTION DIESEL PLANT								
BEAVER CREEK (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	37,488	22,226	26,440	(4,213)	19.2	(219)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	92,859	40,692	50,013	(9,322)	22.0	(424)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	535,779	367,441	350,423	17,018	9.6	1,773
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	173,365	57,856	68,793	(10,937)	26.1	(419)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	48,603	8,070	10,719	(2,649)	34.9	(76)
TOTAL BEAVER CREEK			**888,094**	**496,285**	**506,387**	**(10,102)**		**635**
CARMACKS (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	167,739	43,699	52,552	(8,853)	31.7	(279)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	40,394	25,071	30,815	(5,744)	14.4	(399)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	419,543	309,237	294,915	14,323	8.3	1,726
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	101,158	34,682	40,647	(5,965)	24.7	(242)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	7,366	526	212	314	39.0	8
TOTAL CARMACKS			**736,201**	**413,215**	**419,141**	**(5,926)**		**814**
DESTRUCTION BAY (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	42,282	28,555	37,097	(8,543)	17.2	(497)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	105,478	40,635	67,047	(26,412)	23.3	(1,134)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	488,076	124,970	133,550	(8,580)	21.1	(407)
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	284,627	110,212	174,086	(63,874)	27.7	(2,306)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	28,048	9,297	18,011	(8,714)	34.7	(251)
TOTAL DESTRUCTION BAY			**948,512**	**313,669**	**429,792**	**(116,123)**		**(4,594)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION(LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	608,472	113,608	137,319	(23,711)	34.8	(681)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	619,132	248,855	305,938	(57,083)	21.9	(2,607)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	60,097	37,282	35,555	1,727	11.2	154
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	94,952	47,492	58,093	(10,601)	25.4	(417)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	2,454	1,480	1,989	(509)	36.5	(14)
TOTAL HAINES JUNCTION			**1,385,107**	**448,717**	**538,894**	**(90,177)**		**(3,565)**
OLD CROW (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	187,900	101,869	121,194	(19,324)	21.2	(912)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	215,087	82,975	101,983	(19,008)	24.1	(789)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	1,223,713	529,491	505,966	23,525	15.7	1,498
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	119,365	68,323	80,570	(12,247)	18.9	(648)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	171,496	66,372	91,261	(24,889)	27.3	(912)
TOTAL OLD CROW			**1,917,561**	**849,030**	**900,974**	**(51,944)**		**(1,762)**
PELLY CROSSING (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	48,892	33,045	40,186	(7,140)	15.9	(449)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	129,302	91,469	114,166	(22,697)	27.4	(828)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	474,056	299,952	286,219	13,732	10.9	1,260
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	431,735	151,302	199,681	(48,379)	25.3	(1,912)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	61,485	17,984	27,361	(9,377)	33.4	(281)
TOTAL PELLY CROSSING			**1,145,469**	**593,752**	**667,613**	**(73,860)**		**(2,211)**
ROSS RIVER (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	171,221	56,918	68,182	(11,264)	29.4	(383)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	85,126	32,959	40,510	(7,551)	22.2	(340)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	189,753	147,095	140,282	6,813	7.3	933
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	124,872	48,576	58,732	(10,156)	23.5	(432)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	9,639	1,747	2,208	(461)	35.5	(13)
TOTAL ROSS RIVER			**580,611**	**287,296**	**309,914**	**(22,619)**		**(235)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	247,966	63,443	76,361	(12,918)	32.0	(404)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	65,107	14,921	18,103	(3,182)	28.6	(111)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	45,677	24,846	21,626	3,220	10.9	295
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	70,425	26,610	32,538	(5,928)	24.9	(238)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	84,682	6,880	9,638	(2,758)	38.1	(72)
TOTAL STEWART CROSSING			**513,857**	**136,700**	**158,267**	**(21,567)**		**(530)**
SWIFT RIVER (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	22,503	9,878	11,772	(1,894)	25.6	(74)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	63,430	37,645	46,269	(8,624)	15.7	(549)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	241,047	98,815	94,569	4,245	16.3	260
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	93,560	31,048	37,516	(6,468)	25.1	(258)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	11,924	3,171	4,249	(1,078)	31.3	(34)
TOTAL SWIFT RIVER			**432,465**	**180,557**	**194,375**	**(13,819)**		**(655)**
TESLIN (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	37,986	10,389	12,402	(2,013)	31.2	(65)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	99,863	22,619	27,801	(5,181)	27.5	(188)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	762,034	524,432	500,142	24,290	9.6	2,530
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	54,417	25,006	27,410	(2,404)	21.5	(112)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	69,778	9,088	11,989	(2,901)	35.6	(82)
TOTAL TESLIN			**1,024,077**	**591,534**	**579,744**	**11,790**		**2,084**
WATSON LAKE (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	359,393	203,938	242,320	(38,382)	20.1	(1,910)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	747,818	108,117	132,885	(24,768)	30.6	(809)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	2,169,195	1,318,706	1,256,361	62,346	11.3	5,517
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	578,189	305,256	366,604	(61,348)	22.3	(2,751)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	258,430	61,919	83,525	(21,606)	33.8	(639)
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**2,081,695**	**(83,759)**		**(592)**
TOTAL PRODUCTION DIESEL PLANT			**13,684,978**	**6,308,691**	**6,786,796**	**(478,105)**	**-**	**(10,610)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE								
442.00	STRUCTURES AND IMPROVEMENTS	0	10,662	8,809	10,466	(1,657)	9.3	(178)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	25,562	16,999	20,893	(3,894)	12.8	(304)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	568,500	303,283	287,763	15,520	13.1	1,185
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	87,652	40,799	48,221	(7,422)	23.1	(321)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	92,170	12,008	16,120	(4,112)	35.5	(116)
TOTAL MOBILE			**784,546**	**381,898**	**383,463**	**(1,565)**		**265**
TOTAL GENERATION			**18,192,167**	**7,111,214**	**8,410,233**	**(1,299,018)**		**(21,039)**
SUBSTATION PLANT								
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	1,384,421	626,639	829,972	(203,333)	31.0	(6,559)
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**829,972**	**(203,333)**		**(6,559)**
DISTRIBUTION PLANT								
471.00	LAND RIGHTS	0	1,267,608	151,638	151,507	131	67.3	2
473.00	POLES, TOWERS AND FIXTURES	75-R3	30,231,546	8,972,741	11,487,576	(2,514,836)	33.4	(75,294)
474.00	OVERHEAD CONDUCTOR	45-R3	20,514,612	5,832,601	7,036,909	(1,204,309)	32.3	(37,285)
474.10	OVERHEAD SERVICES	45-R4	2,849,453	1,023,337	1,271,831	(248,494)	33.4	(7,440)
475.00	UNDERGROUND CONDUIT	45-R3	20,982,589	6,074,457	5,608,170	466,287	32.6	14,303
475.10	UNDERGROUND SERVICES	45-R3	2,953,077	924,039	1,049,337	(125,298)	28.5	(4,396)
476.10	METERS	40-R4	1,683,985	682,328	41,448	640,880	10.6	60,460
476.30	AMR - METERS	15-L0	67,646	14,259	-	14,259	12.3	1,159
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	3,131,073	1,605,098	1,950,231	(345,133)	21.5	(16,053)
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	9,147,522	3,814,663	5,173,329	(1,358,667)	21.1	(64,392)
478.20	SENTINEL LIGHTS	30-R3	284,738	246,947	319,069	(72,122)	4.0	(18,030)
479.10	LINE TRANSFORMERS	23-R2	24,427,769	6,695,953	9,796,355	(3,100,402)	37.0	(83,795)
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**43,885,763**	**(7,847,703)**		**(230,761)**
GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	0	3,459,315	1,660,879	2,027,012	(366,133)	23.9	(15,319)
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	172,793	62,511	17,775	44,736	5.5	8,134
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	47,367	10,448	(11,313)	21,761	3.4	6,400
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	2,561,147	964,510	1,693,246	(728,736)	10.0	(72,874)
485.00	TOOLS AND INSTRUMENTS	12-L0	719,184	273,558	239,068	34,490	8.7	3,964
486.00	COMMUNICATION EQUIPMENT	15-SQ	872,842	422,551	391,629	30,922	7.8	3,964
488.20	HOUSES	15-SQ	473,256	152,396	1,717,512	(1,565,115)	21.8	(71,794)
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**6,074,929**	**(2,528,076)**		**(137,525)**
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,322,767**	**59,200,897**	**(11,878,130)**		**(395,883)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION									
HYDRO PLANT (LIFE SPAN OF 2052)									
422.00	HYDRO STRUCTURES	0-ND	(10)	215,286	5,081	813	4,268	64.1	67
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	(10)	1,875,073	19,770	4,367	15,402	97.7	158
425.00	HYDRO GENERATORS	103-R3	(10)	1,458,435	10,442	2,079	8,363	81.9	102
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	(10)	105,192	4,826	657	4,169	34.3	122
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	(10)	68,657	1,945	264	1,681	27.7	61
TOTAL HYDRO PLANT				**3,722,643**	**42,063**	**8,180**	**33,883**		**509**
PRODUCTION DIESEL PLANT									
BEAVER CREEK (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,488	2,223	(3,232)	5,454	19.2	284
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	92,859	8,138	1,494	6,645	22.0	302
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	535,779	36,744	20,345	16,399	9.6	1,708
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	173,365	-	2,313	(2,313)	26.1	(89)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	48,603	-	628	(628)	34.9	(18)
TOTAL BEAVER CREEK				**888,094**	**47,105**	**21,549**	**25,556**		**2,188**
CARMACKS (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	167,739	4,370	(6,423)	10,793	31.7	340
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	40,394	5,014	920	4,094	14.4	284
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	419,543	30,924	17,122	13,801	8.3	1,663
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	101,158	-	1,947	(1,947)	24.7	(79)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	7,366	-	529	(529)	39.0	(14)
TOTAL CARMACKS				**736,201**	**40,308**	**14,095**	**26,213**		**2,195**
DESTRUCTION BAY (LIFE SPAN OF 2023)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	42,282	2,855	(4,534)	7,390	17.2	430
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	105,478	8,127	2,003	6,124	23.3	263
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	488,076	12,497	7,754	4,743	21.1	225
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	284,627	-	882	(882)	27.7	(32)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	28,048	-	239	(239)	34.7	(7)
TOTAL DESTRUCTION BAY				**948,512**	**23,479**	**6,343**	**17,136**		**879**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	608,472	11,361	(16,783)	28,144	34.8	809
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	619,132	49,771	9,138	40,633	21.9	1,855
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	60,097	3,728	2,064	1,664	11.2	149
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	94,952	-	235	(235)	25.4	(9)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	2,454	-	64	(64)	36.5	(2)
TOTAL HAINES JUNCTION				**1,385,107**	**64,860**	**(5,283)**	**70,143**		**2,802**
OLD CROW (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	187,900	10,187	(14,813)	24,999	21.2	1,179
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	215,087	16,595	3,046	13,549	24.1	562
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	1,223,713	52,949	29,376	23,573	15.7	1,501
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	119,365	-	3,340	(3,340)	18.9	(177)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	171,496	-	907	(907)	27.3	(33)
TOTAL OLD CROW				**1,917,561**	**79,731**	**21,856**	**57,875**		**3,033**
PELLY CROSSING (LIFE SPAN OF 2033)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	48,892	3,305	(4,912)	8,216	15.9	517
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	129,302	18,294	3,410	14,884	27.4	543
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	474,056	29,995	16,618	13,378	10.9	1,227
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	431,735	-	1,889	(1,889)	25.3	(75)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	61,485	-	513	(513)	33.4	(15)
TOTAL PELLY CROSSING				**1,145,469**	**51,594**	**17,518**	**34,075**		**2,197**
ROSS RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	171,221	5,692	(8,333)	14,025	29.4	477
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	85,126	6,592	1,210	5,382	22.2	242
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	189,753	14,710	8,145	6,565	7.3	899
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	124,872	-	926	(926)	23.5	(39)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	9,639	-	251	(251)	35.5	(7)
TOTAL ROSS RIVER				**580,611**	**26,993**	**2,199**	**24,795**		**1,572**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	247,966	6,344	(9,333)	15,677	32.0	490
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	65,107	2,984	548	2,436	28.6	85
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	45,677	2,485	1,256	1,229	10.9	113
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	70,425	-	143	(143)	24.9	(6)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	84,682	-	39	(39)	38.1	(1)
TOTAL STEWART CROSSING				**513,857**	**11,813**	**(7,348)**	**19,161**		**681**
SWIFT RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	22,503	988	(1,439)	2,427	25.6	95
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	63,430	7,529	1,382	6,147	15.7	392
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	241,047	9,881	5,491	4,391	16.3	269
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	93,560	-	624	(624)	25.1	(25)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	11,924	-	170	(170)	31.3	(5)
TOTAL SWIFT RIVER				**432,465**	**18,398**	**6,228**	**12,171**		**725**
TESLIN (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,986	1,039	(1,516)	2,555	31.2	82
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	99,863	4,524	830	3,693	27.5	134
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	762,034	52,443	29,038	23,405	9.6	2,438
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	54,417	-	3,301	(3,301)	21.5	(154)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	69,778	-	897	(897)	35.6	(25)
TOTAL TESLIN				**1,024,077**	**58,006**	**32,550**	**25,456**		**2,476**
WATSON LAKE (LIFE SPAN OF 2113)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	359,393	20,394	(29,617)	50,011	20.1	2,488
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	747,818	21,623	3,969	17,654	30.6	577
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	2,169,195	131,871	72,943	58,928	11.3	5,215
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	578,189	-	8,293	(8,293)	22.3	(372)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	258,430	-	2,252	(2,252)	33.8	(67)
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**57,840**	**116,048**		**7,841**
TOTAL PRODUCTION DIESEL PLANT				**13,684,978**	**596,175**	**167,547**	**428,628**	**-**	**26,589**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	10,662	881	(1,279)	2,160	9.3	232
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	25,562	3,400	624	2,776	12.8	217
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	568,500	30,328	16,707	13,621	13.1	1,040
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	87,652	-	1,899	(1,899)	23.1	(82)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	92,170	-	516	(516)	35.5	(15)
TOTAL MOBILE				**784,546**	**34,609**	**18,467**	**16,142**		**1,392**
TOTAL GENERATION				**18,192,167**	**672,847**	**194,194**	**478,653**		**28,490**
SUBSTATION PLANT									
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	(10)	1,384,421	62,664	21,171	41,493	31.0	1,338
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**21,171**	**41,493**		**1,338**
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	0	0	1,267,608	-	(166)	166	67.3	2
473.00	POLES, TOWERS AND FIXTURES	75-R3	(75)	30,231,546	6,729,555	3,685,089	3,044,466	33.4	91,152
474.00	OVERHEAD CONDUCTOR	45-R3	(80)	20,514,612	4,666,080	2,290,803	2,375,277	32.3	73,538
474.10	OVERHEAD SERVICES	45-R4	(10)	2,849,453	102,334	68,292	34,041	33.4	1,019
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	3,037,229	(74,602)	3,111,831	32.6	95,455
475.10	UNDERGROUND SERVICES	45-R3	(10)	2,953,077	92,404	3,618	88,786	28.5	3,115
476.10	METERS	40-R4	0	1,683,985	-	27,423	(27,423)	10.6	(2,587)
476.30	AMR - METERS	15-L0	0	67,646	-	-	-	12.3	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	(10)	3,131,073	160,510	(128,522)	289,032	21.5	13,443
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	(10)	9,147,522	381,466	(265,776)	647,242	21.1	30,675
478.20	SENTINEL LIGHTS	30-R3	0	284,738	-	(105,624)	105,624	4.0	26,406
479.10	LINE TRANSFORMERS	23-R2	(10)	24,427,769	669,595	311,505	358,090	37.0	9,678
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**5,812,042**	**10,027,132**		**341,897**
GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	0	0	3,459,315	-	(135,119)	135,119	23.9	5,654
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	0	172,793	-	(4,613)	4,613	5.5	839
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	0	47,367	-	-	-	3.4	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	25	2,561,147	-	(408,732)	408,732	10.0	40,873
485.00	TOOLS AND INSTRUMENTS	12-L0	0	719,184	-	141	(141)	8.7	(16)
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	-	(6,237)	6,237	7.8	800
488.20	HOUSES	15-SQ	(10)	473,256	15,240	(1,077,696)	1,092,936	21.8	50,135
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**(1,632,256)**	**1,647,495**		**98,283**
TOTAL UTILITY PLANT IN SERVICE			**-**	**145,424,111**	**16,589,924**	**4,395,151**	**12,194,773**	**-**	**470,009**

CW-YECL-35

Reference: Depreciation Study, Application, Section 7, Attachment 1 – Depreciation Study

In order to better understand the historical relationships reflected in net salvage and life analyses, it is necessary to have a better understanding of the type of investment currently in place, the type of investment recently retired, and various accounting practices.

Request:

(a) Please produce all additional working papers or other documentation supporting the depreciation study set out in the Application at Section 7, Attachment 1 including any notes of discussions that Gannett Fleming or Mr. Larry Kennedy had with YECL or employees of YECL.

Response:

(a) The complete basis for Yukon Electrical's position on appropriate Depreciation rates is the Depreciation Study itself, which has been filed and provides the full and comprehensive treatment of the issue. Yukon Electrical is not relying on any further documents or discussions in support of its position.

LE-YECL-4

Reference: Section 3 Purchase Power, Page 3-2

"Deferral Account (b) Diesel Contingency Fund (DCF)"

Request:

(a) Please explain how YECL views the impact of the unavailability of Fish Lake Hydro Unit #1 in 2013 on the DCF.

Response:

(a) The Diesel Contingency Fund (DCF), as previously approved, serves to stabilize Yukon Energy's and Yukon Electrical's costs to serve firm load on the grid due to variances in actual water flows relative to approved long term averages. As such, it is Yukon Electrical's position that any impact due to the unavailability of Fish Lake Hydro Unit #1, because it is not due to a variance in water flows, will not be incorporated into the DCF calculations until such time as Hydro Unit #1 is back up and operational.

LE-YECL-7

Reference: Section 5 Operations and Maintenance Expenses, Page 5-5

Discontinuance of Third Party Distribution Line (Property Insurance) "*Going back to the year 2008, Yukon Electrical has researched its claims history ...*"

Request:

A 5 year claim history in which the annual premiums do not add up to one deductible would seem to be too short. Please provide a 20 year (or more) claim history.

Response:

Yukon Electrical has reviewed its claim history going back to 1993 and is able to confirm there have been no claims on the third party distribution line insurance policy through to present.

LE-YECL-9

Reference: Section 7 Depreciation, Page 7-2

Deferral on Depreciation Parameters

Request:

(a) YECL is under the same IFRS requirements as Yukon Energy yet YECL's approach appears to be very different. Please explain the differences in approach, explain why YECL wants to take the approach proposed here, and show how it is beneficial to ratepayers.

(b) Please explain why the changes discussed on pages 7-2 to 7-4 could not be accommodated in appropriate changes in a GRA every 3 years if YECL proposes to make adjustments only if the significant change takes place over 2 or 3 years in any case?

Response:

(a) Notably, Yukon Energy had not yet transitioned to IFRS at the time of filing of its 2012/2013 GRA. When it implements IFRS, Yukon Energy will have the same requirement as Yukon Electrical to review its depreciation parameters annually and implement new depreciation rates if necessary. Yukon Electrical implemented IFRS in 2011 and has since dealt with increased administrative burden due to keeping two sets of financial records. Because of this experience, Yukon Electrical has requested the deferral on depreciation parameters in order to harmonize IFRS and regulatory accounting in the area of depreciation to avoid even further complexity and accounting costs due to yet another difference between the two sets of financial records and, in turn, the need for more accounting and higher accounting related costs.

(b) Significant changes in the expected life of assets or gross salvage and costs of retirement of assets can be caused by various events, including changes in technology or the life experience of the asset in the field. Such an event or events could have an immediate impact on the expected life of assets or gross salvage and costs of retirement in the same year in which in which it occurs. Conversely, such event or events could have an impact on the expected life of

assets or gross salvage and costs that is not immediate but is only revealed after several years of data and trend information is analyzed. Yukon Electrical would be required to update its depreciation parameters if either type of situation were to occur, not only for significant changes that take place over 2 or 3 years.

If a change to depreciation parameters is required based on Yukon Electrical's annual review of depreciation parameters as described on pages 7-2 and 7-3 of the Application, Yukon Electrical would be obligated to adjust the depreciation parameters and the resulting depreciation rates for financial statement purposes in order to obtain a clean audit opinion under IFRS. While the update to the depreciation parameters for regulatory purposes could wait until Yukon Electrical's next GRA is filed, this delay would create yet another difference between Yukon Electrical's IFRS and regulatory financial records, which, in turn, creates the need for more accounting and higher accounting related costs.

LE-YECL-10

Reference: Section 7 Depreciation, Schedules 7.2 to 7.4

Request:

Please explain in detail why the proposed depreciation rates for a number of asset classes vary so much from year to year within the test period.

Response:

The reason for depreciation rates varying from year to year is due to 1) the effects of the Equal Life Group (ELG) procedure, 2) reduced period of recovery for applicable life span accounts[i] and 3) capital additions and retirements for each forecast year. LE-YECL-10 Attachment 1 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2013. As shown, the total original cost in this account as of the end of 2012 is $262,558 with the applicable vintage details. The total expected depreciation expense (i.e. annual accrual) adjusted for net salvage is forecast to be $6,307. This expected depreciation expense divided by the total original cost of $262,558 results in a forecast depreciation rate of 2.40% for 2013. LE-YECL-10 Attachment 2 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2014. Consistent with the ELG procedure, as a particular vintage ages each successive year's depreciation rate for that vintage will decrease accordingly and if no capital activity occurs during a year then the composite account depreciation rate will similarly decrease. As this account is also using a Life Span grouping with a terminal year of 2052, the recovery period for each successive vintage's additions are compressed resulting in higher associated depreciation rates. For this account, approximately $197,000 is forecast to be added during 2013. This significant addition attracts a vintage depreciation rate of 3.04%. The investment weighted calculation of vintage depreciation expense produces a composite depreciation rate of 2.79%. LE-YECL-10 Attachment 3 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2015. The forecast addition for the 2014 vintage is $167,000. This large addition attracts a vintage depreciation rate of 3.10% due to the ELG methodology described above and the compressed time to recover the investment for the 2014 vintage by the lifespan retirement date of 2052. This results in an account composite depreciation rate of 2.91%.

[i] Please refer to YUB-YECL-81(b) for a discussion on lifespan analysis.

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2013
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2013

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.43	152.47	.6006	6,404
1987	67,520.32	1.73	1,168.10	.4498	30,371
1989	57,730.91	1.78	1,027.61	.4272	24,663
1991	308.57	1.83	5.65	.4026	124
1992	11,156.06	1.86	207.50	.3906	4,358
2000	10,832.25	2.14	231.81	.2782	3,014
2010	21,239.34	2.73	579.83	.0819	1,740
2011	83,108.03	2.84	2,360.27	.0568	4,721
			5,733.24		75,395
NET SALVAGE ADJUSTMENT			573.32		7,540
TOTAL	262,557.87		6,306.56		82,935

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.40

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2013

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		16.0	262,557.87	2.40	6,307	82,935
GRAND TOTAL		16.0	262,557.87	2.40	6,307	82,935

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2014
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2014

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.42	151.41	.6106	6,510
1987	67,520.32	1.72	1,161.35	.4644	31,356
1989	57,730.91	1.77	1,021.84	.4425	25,546
1991	308.57	1.82	5.62	.4186	129
1992	11,156.06	1.85	206.39	.4070	4,541
2000	10,832.25	2.13	230.73	.2982	3,230
2010	21,239.34	2.69	571.34	.1076	2,285
2011	83,108.03	2.78	2,310.40	.0834	6,931
2013	197,000.00	3.04	5,988.80	.0304	5,989
			11,647.88		86,517
NET SALVAGE ADJUSTMENT			1,164.79		8,652
TOTAL	459,557.87		12,812.67		95,169

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.79

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2014

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		10.1	459,557.87	2.79	12,813	95,169
GRAND TOTAL		10.1	459,557.87	2.79	12,813	95,169

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2015
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2015

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.41	150.34	.6204	6,615
1987	67,520.32	1.71	1,154.60	.4788	32,329
1989	57,730.91	1.76	1,016.06	.4576	26,418
1991	308.57	1.81	5.59	.4344	134
1992	11,156.06	1.84	205.27	.4232	4,721
2000	10,832.25	2.12	229.64	.3180	3,445
2010	21,239.34	2.66	564.97	.1330	2,825
2011	83,108.03	2.74	2,277.16	.1096	9,109
2013	197,000.00	2.94	5,791.80	.0588	11,584
2014	167,000.00	3.10	5,177.00	.0310	5,177
			16,572.43		102,357
NET SALVAGE ADJUSTMENT			1,657.24		10,236
TOTAL	626,557.87		18,229.67		112,593

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.91

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2015

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		8.4	626,557.87	2.91	18,230	112,593
GRAND TOTAL		8.4	626,557.87	2.91	18,230	112,593

LE-YECL-11

Reference: Section 8 Return on Rate Base, Page 8-4 and 8-5

Business Risk Analysis

Request:

(a) Does YECL face greater or less business risk than Yukon Energy? Please explain.

(b) For the period of 2008 to 2012 please provide a table showing Board approved and actual ROEs achieved by YECL.

Response:

(a) Looking backwards, Yukon Electrical has acknowledged that Yukon Energy relative to Yukon Electrical has more risk. On a go forward basis, however, it is difficult to provide a definitive answer as Yukon Electrical's generation assets are forecast to become a larger percentage of its asset mix as compared to 2008. The presence of generation assets in rate base generally increases the business risk relative to a pure distribution utility, as the operational risks associated with generation exceed those of wires operations. Please refer to the following table for Yukon Electrical's actual asset mix in 2008, 2012 as well as forecast through to 2015.

	Actual		GRA		
	2008	**2012**	**2013**	**2014**	**2015**
Generation	14%	13%	16%	18%	19%
Distribution	79%	81%	77%	75%	74%
Other	7%	6%	7%	7%	7%
Total	100%	100%	100%	100%	100%

In YUB-YECL-31, Yukon Electrical has also identified changes to its market demand and operational costs that have resulted in Yukon Electrical's business risk increasing modestly since 2008.

Finally in response to this question, Yukon Electrical notes that Yukon Energy has maintained the same capital structure since 1992 and did not request or provide evidence to support a change to it as part of its 2012-2013 GRA. Further to this, Yukon Energy stated the following in its 2012-2013 GRA reply argument:

> Yukon Energy notes that the current proceeding provides no reasonable or tested evidence upon which the Board could support a revision of YEC's capital structure, or assess YEC's capital structure based on AUC methods.

In dealing with this matter, the Board stated the following in Board Order 2013-01:

> YEC's capital structure of 60-percent debt and 40-percent equity has been previously approved by the Board, most recently through Board Order 2009-8. Nothing on the record of this proceeding persuades the Board to alter the applied-for and previously approved capital structure for YEC.

Contrary to the above noted evidentiary situation, this Application continues to rely on the business risk expert evidence from Yukon Electrical's 2008-2009 GRA as well as regulatory decisions in the Northwest Territories and British Columbia. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(b) Please refer to LE-YECL-11(b) Attachment 1.

Yukon Electrical 2008 - 2012
Board Approved vs. Actual Return on Equity

Year	2008	2009	2010	2011	2012
Approved	9.08%	8.93%	N/A	N/A	N/A
Actual	7.03%	11.35%	10.54%	10.74%	10.18%
Difference	-2.05%	2.42%	N/A	N/A	N/A

LE-YECL-12

Reference: Section 8 Return on Rate Base, Page 8-6

Forecast Long Term Date [sic] Rates

Request:

Please provide a list of the financial institutions referred to and each of their forecasts for long term debt rates for the period 2013 to 2020.

Response:

The financial institutions referred to included BMO Capital Markets, TD Economics, RBC Economics and Consensus Forecasts. Please refer to WL-YECL-18(c) Attachments 1 through 4 for the latest available forecasts used in determining the long term debt rate forecast from 2013 to 2015.

LE-YECL-15

Reference: Section 11 Prior Board Directions, Attachment 2 Pages 11-15-16, and Page 1-6

Request:

For each of the utility filings listed here please also provide the labour inflation rates requested by these utilities.

Response:

ATCO Electric (2011-2012 GTA)

- AE requested approval of labour inflation rates of 3.0% for each of the 2011 and 2012 test years.

AltaLink (2011-2012 GTA)

- AML requested approval of labour inflation rates of 4.24% for salaries and wages (labour), 4.50% for union, 4.00% for non-union and 3.00% for executives for each of the 2011 and 2012 test years.

EPCOR (2012 GTA)

- EDTI requested approval of labour inflation rates of 4.0% for non-union labour, 3.0% for Civic Service Union 52 labour, and 3.0% for International Brotherhood of Electric Workers for 2012.

Fortis (2012 GTA)

- FAI requested approval of labour inflation rates of 3.0% for association labour and 4.0% for non-association labour for 2012.

Northland Utilities (NWT) (2011-2013 GRA)

- NUL (NWT) requested approval of labour inflation rates of 3.5%, 3.0%, and 3.0% for the 2011, 2012, 2013 test years, respectively.

Northland Utilities (NUY) (2011-2013 GRA)

- NUL (NUY) requested approval of labour inflation rates of 3.5%, 3.0%, and 3.0% for the 2011, 2012, 2013 test years, respectively.

LE-YECL-24

Reference: Section 13 Business Cases, Business Case #30

Request:

(a) Please confirm that the DSM plan is a joint YECL – Yukon Energy plan that will be supported and implemented by both utilities.

(b) Please confirm that it will be a separate joint YECL – Yukon Energy witness panel that will be available for cross-examination on the DSM plan.

(c) Page 3 of 7: "*The plan was developed by the utilities in collaboration with interveners, Yukon NGOs, community leaders, First Nation Governments and the general public*"

(i) Did any party other than the utilities have any role other than to provide input to the utilities and their DSM consultants?
(ii) Did any party other than the utilities have final decision making authority as to the content and detail of the final DSM plan?
(iii) Did any of parties included in the list above indicate to the utilities at any time that they wished to see a more aggressive DSM plan?

(d) Page 7 of 7: Please confirm that the utilities were ordered by the Board to work together to develop DSM policies.

Response:

(a) Yes, the DSM plan is a joint plan and will be implemented jointly by both utilities.

(b) The utilities are supportive of a separate panel to examine the DSM Plan.

(c) (i) The Yukon government, through the Energy Solutions Centre (ESC), provided input through the Conservation Potential Review phase of the plan development. ESC was also a member of the DSM Working Group and DSM Steering Committee.

(ii) No party other than the utilities had final decision making authority as to the content and detail of the final DSM Plan.

(iii) Input of that nature was not recorded.

(d) Yes, the utilities were ordered by the Board to work together to develop the DSM plan under Board Orders 2009-2, 2009-8, 2010-13.

LE-YECL-26

Reference: Section 13 Business Cases, Page 7: 4.2 Yukon Electrical Company Limited (YECL)

Request:

(a) "... *Yukon Electrical will develop and implement ... which meet the economic thresholds ... , as well as Yukon Electrical's mandate*." Please describe YECL's 'mandate' referred to here, and where it originates.

Response:

(a) Yukon Electrical's mandate is to deliver high value to its customers through the provision of safe, reliable, innovative and cost effective electric service.

LE-YECL-27

Reference: Section 13 Business Cases, Page 9 The Yukon five year DSM plan description starts in section 5.

Request:

(a) Please describe the programs each utility has undertaken internally to reduce own building or system wide electrical energy consumption (such as transformer loss reduction).

(b) Have any specific peak shaving program components been undertaken in this five year DSM plan?

(c) Have any specific peak load shifting (from peak to off-peak) components such as water heater timers/controls or the promotion of electric-thermal storage units (to replace baseboard electric heaters) been undertaken in this five year DSM plan?

(d) Has the government given any indication that they would support an approach to regulating the sale of devices of certain design standards to reduce consumer phantom loads (of electronics in particular – e.g. charging transformers that do not turn off when their load is disconnected)?

Response:

(a) Yukon Electrical continues to make internal system efficiency improvements and to address opportunities to improve energy efficiency within its various facilities. System improvements include: the conversion of Hillcrest subdivision to a higher voltage to reduce losses; designing the large transformers at Whistle Bend and at the Shipyard substation to ensure impedances are optimized to reduce internal losses; the current plans for building envelope improvements for the downtown office; insulation upgrades implemented in various plants; and air handling balancing and HVAC replacement in the service complex building. These improvements are outside the scope of the joint DSM plan.

Yukon Energy has completed some additional internal efficiency projects, pilot projects and public education initiatives, these activities along with the joint utility initiatives are outlined in section 5.3.1.5 of Yukon Energy's

2012-2013 General Rate Application and Yukon Energy's IR response YUB-YEC-46(d) Attachment 1. These activities are not part of the joint DSM plan. Costs associated with Yukon Energy's activities outside the joint DSM plan are not part of this application.

(b) There has been no specific peak shaving program components undertaken in the joint DSM plan.

(c) There has been no specific peak load shifting program component undertaken in the joint DSM plan.

(d) No, the government has not given any indication of support to an approach that would regulate the sale of certain devices.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

UCG-YECL-4

Reference: May 27, 2013 Application Cover Letter, page 2

YECL states "*In Section 12 of this Application, Yukon Electrical has requested approval of a 6.5% interim refundable rate rider (Rider R) for electrical consumption on or after July 1 2013. By implementing the rate on July 1, 2013, Rider R will recover approximately 50% of Yukon Electrical's forecast shortfall in 2013.*"

Request:

Please provide details of all expected recoveries through Rider R by month for the period July 2013 through December 2014.

Response:

As Yukon Electrical does not have monthly revenue information for Yukon Energy, Yukon Electrical cannot provide expected Rider R recoveries per month. As shown in Schedule 12.1 of Yukon Electrical's 2013-2015 GRA application, the expected recovery for July to December 2013 is $1,825,000 while, at a continued interim refundable rate rider (Rider R) of 6.5%, the expected recovery for the period January to December 2014 would be approximately $4,067,000 as demonstrated in the table below.

Company	2014 Retail Revenue ($000s) [1] (A)	Rider R % [2] (B)	Expected Rider R Revenue ($000s) (A) * (B)
YECL	$50,393	6.5%	$3,276
YEC	$12,169	6.5%	$ 791
Total	$62,562		$4,067

[1] Retail revenue on existing rates, YECL 13/15 GRA Application, Schedule 2.1 L.56-58

[2] As approved in Board Order 2013-05 dated June 25, 2013

UCG-YECL-5

Reference: May 27, 2013 Application, page 1-3

YECL states "*Yukon Electrical was last before the Yukon Utilities Board ("Board") for the test years 2008-2009. Since then, Yukon Electrical has operated on 2009 primary rates with the exception of flowing through the impact of changes in fuel prices in accordance with Rider F and the Fuel Price Flow Through Deferral mechanism, as well as flowing through the impact of changes in the wholesale energy tariff from the Yukon Energy Corporation in accordance with the Purchased Power Flow Through Deferral mechanism.*"

Request:

(a) Please confirm that the bills of Yukon ratepayers have continued to change since 2008 due to the reliance by YEC and YECL on across-the-board percentage rate riders (e.g., Riders F, J and R) to recover approved rate revenue requirements and changes to fuel costs beyond what was provided by base rates.

(b) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for a residential customer living in Whitehorse using 1000 kWh, 1200 kWh and 1400 kWh per month in January 2008, January 2009, January 2010, January 2011, January 2012, January 2013, January 2014 and January 2015 assuming that the 2013, 2014 and 2015 rate adjustments proposed by YECL are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

(c) Please provide details of YECL's understanding of mitigation efforts in other jurisdictions if rate adjustments result in bill impacts in excess of a specific threshold.

(d) Please provide details of YECL's position regarding mitigation efforts that should be imposed if rate adjustments in the Yukon result in bill impacts in excess of 10%.

Response:

(a) Confirmed. Please note that Fuel Adjustment Rider, Rider F, is not applied on an across-the-board percentage basis, but is applied on a cents per kWh basis to consumption.

(b) Please refer to UCG-YECL-5(b) Attachment 1 for the requested detailed bill calculations.

(c) Yukon Electrical is aware of three rate impact mitigation methods that other jurisdictions have used:

1) Government Subsidy

An example of this mitigation method recently occurred in the Northwest Territories Power Corporation's (NTPC) 2012-14 GRA where the Government of the Northwest Territories (GNWT) provided subsidization to NTPC to assist in transitioning rates to recover the full 2013-14 revenue requirement by the end of a 4-year transition period.

2) Collecting approved balances over a longer period of time

This approach has been used by ATCO Electric as well as Northland Utilities depending on the circumstances. For example, when considering the collection of approved amounts, utilities will consider the rate impact to customers and will propose a recovery period that achieves a balance between the utility being able to recover approved costs and the recovery rate not resulting in rate shock.

3) Cross-subsidization between rate classes

If the cost of service and a 100% revenue to cost ratio for a particular rate class results in rate shock for a particular rate class, the utility may propose a revenue to cost ratio of less than 100%. This effectively results in customer class cross-subsidization.

(d) Yukon Electrical's position on this has been, and continues to be, that if a bill increase at a point in time (month over month) exceeds 10%, any of the three methods that might be available as described in part (c) can be employed to address rate shock. Further to this, however, and as detailed in UCG-YECL-5(d) Attachment 1, there have been a couple of instances in the past 20 years where Yukon residential non-government bills have increased by more than 10%. Yukon Electrical also notes the Northwest Territories PUB has set a bill increase cap of 15% with respect to Northland Utilities (NWT). Finally, also as detailed in UCG-YECL-5(d) Attachment 1, Yukon Electrical notes there will be no bill increases in 2014 or 2015 approaching 10% based on information currently available to Yukon Electrical.

Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1000 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1000	1000	1000	1000	1000	1000	1000	1000	1000
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
Rates	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
Rates	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
Relief	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BASE RATE		$ 110.50	$ 110.50	$ 110.50	$ 110.50	$ 136.05	$ 136.05	$ 136.05	$ 136.05	$ 136.05
	RIDER F - FUEL ADJUSTMENT RIDER		$ 9.64	$ 18.60	$ (3.54)	$ (0.90)	$ 3.52	$ 1.91	$ 1.91	$ 1.91	$ 1.91
	APPEAL RIDER										
	YEC SHORTFALL		$ 16.50	$ 12.65	$ 13.77	$ 13.77	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 8.71	$ 14.98	$ 14.98	$ 14.98
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 5.10	$ 4.93	$ -	$ -
	YECL SHORTFALL		$ -	$ 5.53	$ 11.63	$ 11.63	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 8.84	$ 16.46	$ 16.46
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.05	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 136.64**	**$ 147.28**	**$ 132.36**	**$ 135.00**	**$ 139.57**	**$ 151.77**	**$ 166.71**	**$ 178.45**	**$ 169.40**
	% Change M over M (Before Relief)			7.8%	-10.1%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.55)	$ (0.55)	$ (0.55)	$ (0.55)	$ (1.02)	$ (1.02)	$ (1.02)	$ (1.02)	$ (1.02)
	TOTAL RELIEF		$ (19.12)	$ (19.12)	$ (27.16)	$ (27.16)	$ (27.63)	$ (27.63)	$ (27.63)	$ (27.63)	$ (27.63)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 117.52**	**$ 128.16**	**$ 105.20**	**$ 107.84**	**$ 111.94**	**$ 124.14**	**$ 139.08**	**$ 150.82**	**$ 141.77**
	% Change M over M (Including Relief)			9.1%	-17.9%	2.5%	3.8%	10.9%	12.0%	8.4%	-6.0%

(1) Reflects Rates per Board Order 2013-04 with respect to Yukon Energy's 2012-2013 GRA
(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief

Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1200 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1200	1200	1200	1200	1200	1200	1200	1200	1200
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
Rates	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
Rates	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ 20.90	$ 20.90	$ 20.90	$ 20.90	$ 25.64	$ 25.64	$ 25.64	$ 25.64	$ 25.64
	BASE RATE		$ 131.40	$ 131.40	$ 131.40	$ 131.40	$ 161.69	$ 161.69	$ 161.69	$ 161.69	$ 161.69
	RIDER F - FUEL ADJUSTMENT RIDER		$ 11.57	$ 22.32	$ (4.25)	$ (1.08)	$ 4.22	$ 2.29	$ 2.29	$ 2.29	$ 2.29
	APPEAL RIDER										
	YEC SHORTFALL		$ 19.62	$ 15.05	$ 16.37	$ 16.37	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 10.35	$ 17.80	$ 17.80	$ 17.80
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 6.06	$ 5.85	$ -	$ -
	YECL SHORTFALL		$ -	$ 6.57	$ 13.83	$ 13.83	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 10.51	$ 19.56	$ 19.56
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.75	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 162.59**	**$ 175.34**	**$ 157.35**	**$ 160.52**	**$ 165.91**	**$ 180.39**	**$ 198.14**	**$ 212.09**	**$ 201.34**
	% Change M over M (Before Relief)			7.8%	-10.3%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.66)	$ (0.66)	$ (0.66)	$ (0.66)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)
	TOTAL RELIEF		$ (19.23)	$ (19.23)	$ (27.27)	$ (27.27)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 143.36**	**$ 156.11**	**$ 130.08**	**$ 133.25**	**$ 138.09**	**$ 152.57**	**$ 170.32**	**$ 184.27**	**$ 173.52**
	% Change M over M (Including Relief)			8.9%	-16.7%	2.4%	3.6%	10.5%	11.6%	8.2%	-5.8%

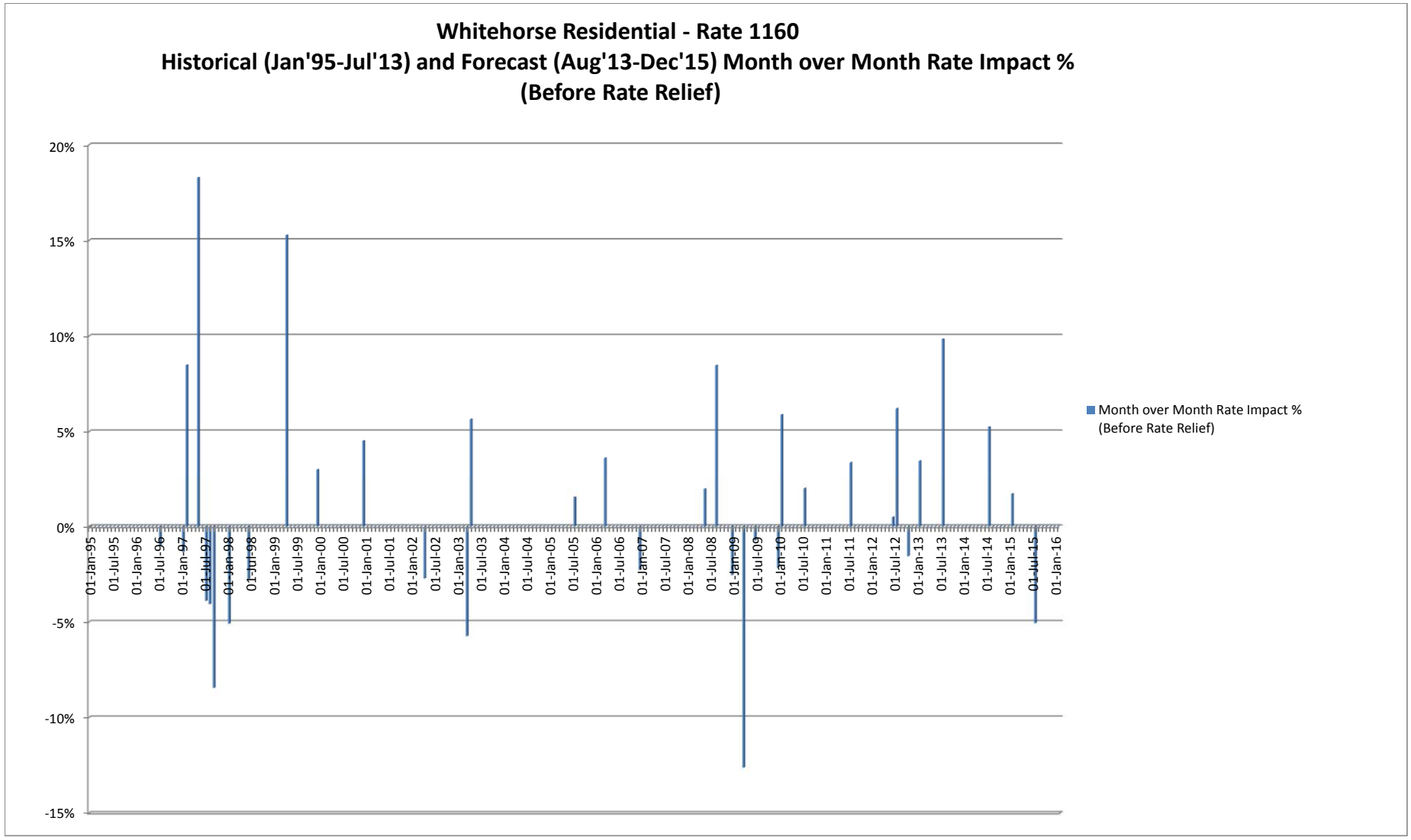
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(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief

Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1400 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1200	1200	1200	1200	1200	1200	1200	1200	1200
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
Rates	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
Rates	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ 20.90	$ 20.90	$ 20.90	$ 20.90	$ 25.64	$ 25.64	$ 25.64	$ 25.64	$ 25.64
	BASE RATE		$ 131.40	$ 131.40	$ 131.40	$ 131.40	$ 161.69	$ 161.69	$ 161.69	$ 161.69	$ 161.69
	RIDER F - FUEL ADJUSTMENT RIDER		$ 11.57	$ 22.32	$ (4.25)	$ (1.08)	$ 4.22	$ 2.29	$ 2.29	$ 2.29	$ 2.29
	APPEAL RIDER										
	YEC SHORTFALL		$ 19.62	$ 15.05	$ 16.37	$ 16.37	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 10.35	$ 17.80	$ 17.80	$ 17.80
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 6.06	$ 5.85	$ -	$ -
	YECL SHORTFALL		$ -	$ 6.57	$ 13.83	$ 13.83	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 10.51	$ 19.56	$ 19.56
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.75	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 162.59**	**$ 175.34**	**$ 157.35**	**$ 160.52**	**$ 165.91**	**$ 180.39**	**$ 198.14**	**$ 212.09**	**$ 201.34**
	% Change M over M (Before Relief)			7.8%	-10.3%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.66)	$ (0.66)	$ (0.66)	$ (0.66)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)
	TOTAL RELIEF		$ (19.23)	$ (19.23)	$ (27.27)	$ (27.27)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 143.36**	**$ 156.11**	**$ 130.08**	**$ 133.25**	**$ 138.09**	**$ 152.57**	**$ 170.32**	**$ 184.27**	**$ 173.52**
	% Change M over M (Including Relief)			8.9%	-16.7%	2.4%	3.6%	10.5%	11.6%	8.2%	-5.8%

(1) Reflects Rates per Board Order 2013-04 with respect to Yukon Energy's 2012-2013 GRA
(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief


Whitehorse Residential - Rate 1160
Historical (Jan'95-Jul'13) and Forecast (Aug'13-Dec'15) Month over Month Rate Impact %
(Before Rate Relief)
20%
15%
10%
5%
0%
-5%
-10%
-15%
01-Jan-95
01-Jul-95
01-Jan-96
01-Jul-96
01-Jan-97
01-Jul-97
01-Jan-98
01-Jul-98
01-Jan-99
01-Jul-99
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01-Jan-09
01-Jul-09
01-Jan-10
01-Jul-10
01-Jan-11
01-Jul-11
01-Jan-12
01-Jul-12
01-Jan-13
01-Jul-13
01-Jan-14
01-Jul-14
01-Jan-15
01-Jul-15
01-Jan-16
Month over Month Rate Impact %
(Before Rate Relief)

UCG-YECL-6

Reference: May 27, 2013 Application, page 1-4

YECL states "*Further to the above, the Board directed in Board Order 2010-13 that a joint Cost of Service Study was to be filed within six months of the expiry of OIC 2008/149. Given that OIC 2008/149 was superseded by OIC 2012/68 with the effect of no rate rebalancing until after December 31, 2013, Yukon Electrical is now forecasting a joint Phase II GRA with Yukon Energy will be filed in 2014 that will include a Cost of Service Study, Rate Design, Rate Schedules and Terms and Conditions based on Yukon Electrical's and Yukon Energy's most recently approved revenue requirements.*"

Request:

(a) Please provide details of the steps that YECL expects to take to compile and submit a joint Phase II GRA as well as the amount of time needed to finish these steps.

(b) Please provide details on what work has been completed to date on the next Phase II GRA and/or when this work is to commence.

Response:

(a) Assuming OIC-2008/149 which was amended by OIC-2012/68 expires on December 31, 2013 and utilities are expected to file a joint phase application within 6 months of the expiry of the rate directive, as ordered in Board Order 2010-13, Yukon Electrical and Yukon Energy will work together to submit a joint Phase II GRA based on the total 2013 revenue requirement of the two utilities. It is expected that the joint cost of service study and rate design will commence in late 2013 utilizing Yukon Electrical's proposed 2013 revenue requirement and Yukon Energy's approved 2013 revenue requirement. Based on the experience associated with the 2010 joint Phase II, Yukon Electrical forecasts that it may take between 4 to 6 months to prepare this application.

(b) No work on the next Phase II GRA has commenced to-date. It is expected that this work will commence in late 2013.

UCG-YECL-8

Reference: May 27, 2013 Application, pages 2-1 – 2-2

YECL states "*Yukon Electrical forecasts the total primary non-industrial sales in 2013 to increase 2.3% (on a weather-normalized basis) and 1.9% in each of 2014 and 2015. The 2.3% growth in sales in 2013 is consistent with the recently applied for and Board approved Yukon Energy 2013 forecast growth in wholesale sales to Yukon Electrical of 2.26%. Including the sales to the Yukon Electrical industrial customer, Whitehorse Copper Tailings, the growth in total sales in 2013 to 2015 would be 2.6%, 3.1% and 1.9%, respectively.*"

Request:

(a) Please confirm whether the electrical sales by customer class shown at the top of page 2-2 for the 2013-2015 test period are weather normalized.

(b) Please confirm the 2013 forecast wholesale sales approved by the YUB for Yukon Energy Corporation in its Order 2013-03 issued on June 17, 2013.

(c) Please provide details on when YECL's current sales forecasts for 2013-2015 were determined for this rates application.

(d) Please identify the impact that demand side management is expected to have on sales levels in 2013, 2014 and 2015. Explain how this impact has been incorporated into the sales forecast and provide a revised version of Schedule 2.1 showing the sales forecast for 2013 – 2015 with DSM impacts isolated.

(e) Please provide monthly details of Whitehorse Copper's forecasted electricity use, demand and bill component totals for 2013, 2014 and 2015.

Response:

(a) As indicated on page 2-5 of the Application, the residential energy consumption forecast presented on Table 1 is derived based on a weather-normalized UPC, with the exception of energy consumption for Keno City, Stewart Crossing and Swift River, where their actual UPC were used. For all practical purposes, however, the residential energy forecast on Table 1 should be considered

weather-normalized, as the combined share of energy consumption of those communities indicated above accounts for only a marginal fraction of the Yukon's total residential energy consumption (0.2% in 2012, please refer to Table 3, page 2-4 of the Application).

As for the commercial energy consumption forecast presented in Table 1, as indicated on page 2-6 of the Application, only Whitehorse commercial UPC was weather-normalized, however, Whitehorse commercial energy consumption accounts for a significant share of Yukon's total commercial energy consumption (85.3% in 2012, please refer to Table 3, page 2-4 of the Application).

Energy consumption related to Street and Private lights presented in Table 1 are not weather-normalized.

(b) Based on Schedule 9 of Yukon Energy's, June 20, 2013, Compliance Re-filing, wholesale sales were approved to be 307,147 MWh for 2013.

(c) The sales forecast for this GRA was developed between February and April of 2013 utilizing actual sales data up to December 31, 2012.

(d) Demand Side Management is assumed to be approved to commence in 2014, and its total impact is forecast to be a reduction in sales of 99 MWh in 2014 and 707 MWh in 2015. Please refer to WL-YECL-8(a) Attachment 1 for more detail.

(e) Please refer to UCG-YECL-8(e) Attachment 1 for the requested information.

The Yukon Electrical Company Limited
Industrial Rate Forecast

Industrial Primary Rate Schedule 39 effective January 1, 2012

Demand Charge	$ per kVA	$ 15.94
Energy	$/kWh	$0.0808

Forecast Charge Demand (kVA):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	1,250	1,250	1,250	3,750
2014	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
2015	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000

Forecast Energy (kWh):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	520,800	504,000	-	1,024,800
2014	-	-	520,800	504,000	520,800	504,000	520,800	520,800	504,000	520,800	504,000	-	4,620,000
2015	-	-	520,800	504,000	520,800	504,000	520,800	520,800	504,000	520,800	504,000	-	4,620,000

Forecast Revenue ($000):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	62	61	20	143
2014	20	20	62	61	62	61	62	62	61	62	61	20	612
2015	20	20	62	61	62	61	62	62	61	62	61	20	612

UCG-YECL-9

Reference: May 27, 2013 Application, page 2-5

YECL states "*Weather-normalized UPC is obtained based on a two-step approach where, in the first step, the historical average monthly UPC is regressed on reported monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in first step is multiplied by the difference between the actual HDD and the "Normal" HDD. "Normal" HDD is defined as a twenty-year rolling average of HDD.*"

July 27, 2012 YEC 2012-2013 GRA, YECL-YEC-1-3

YEC states "*Heating Degree Days (HDD) analysis showed that the temperature in Whitehorse was colder in 2011 than the 10-year average. HDD for 7 winter months (Jan-Apr, Oct-Dec) showed approximately 66 higher HDD in 2011 compared to 10-year average (columns B and C in Table 1 of Attachment 1)*.

Request:

(a) Please provide the source documents for the monthly heating degree days provided in the Application at Section 2, Attachment 20.

(b) Please provide details of when the YUB approved the use of the 20 year rolling average Heating Degree Days as a method of normalizing YECL's temperature-sensitive sales.

(c) Please explain the difference between the 2011 heating degree days for Whitehorse identified by YEC as "actual" and the 2011 "actual" heating degree days provided in YECL's Application at Section 2, Attachment 20.

Response:

(a) Please refer to Environment Canada's website (http://climate.weather.gc.ca/).

(b) In Yukon Electrical's 2008-2009 GRA, Yukon Electrical used 20-year rolling average heating degree days (HDD) to define "Normal" temperature used in its weather normalization. The Board implicitly approved Yukon Electrical's

definition of "Normal" temperature, as there was no objection raised in Board Order 2009-2 issued on February 12, 2009. ATCO Electric and Fortis Alberta have previously used a 20-year rolling average HDD in their past General Tariff Applications with the Alberta Utilities Commissions, which have been approved. Furthermore, many utilities in Canada and the U.S. have used that definition of "Normal" temperature as evidenced in Itron's 2005 survey (please refer to Table 1, Section 11, Attachment 1 of the Application).

(c) Yukon Energy reported HDD of 6,649 for Whitehorse in 2011 (Source: 2012-2013 Yukon Energy GRA, YECL-YEC-1-1(a) Attachment 1), while Yukon Electrical reported 6,685 for Whitehorse for the same year. Although the difference is not large enough to materially change the sales forecast, the difference could be due to one or a combination of the following factors:

- Environment Canada's revisions to reported weather data;
- Using a different weather station in Whitehorse. For example, there are 2 weather stations in Whitehorse whose weather data is reported by Environment Canada on their website cited in part (a) above; and or
- The estimating method used by each utility for missing data. Yukon Electrical notes that there has been missing weather data reported by Environment Canada with increased frequencies in recent years.

UCG-YECL-10

Reference: May 27, 2013 Application, page 2-8

YECL states "*As WHCT is a single industrial customer that could contribute materially higher or lower than 1.4% of Yukon Electrical's total forecast sales and the exact timing of its start-up and eventual load are not within the control of Yukon Electrical, Yukon Electrical is requesting a deferral account relating to WHCT sales uncertainty. This deferral account is proposed to capture the difference between WHCT net revenue on existing Rate 39 less forecast purchase power price applied to forecast sales, and WHCT net revenue on existing Rate 39 less forecast purchased power price applied to actual sales. The net revenue will be defined using Rate 39 effective January 1, 2013, that was used to generate the revenue on existing rates in Schedule 2.1, less the forecast price of purchase power stated in Schedule 3.1 assumed in the revenue requirement. Differences between forecast and actual will be refunded to or collected from customers.*"

Request:

(a) Please provide examples where the YUB has allowed the creation of a deferral account related to the sales forecast of a utility.

(b) Please explain how the requested deferral account lessens the risk faced by YECL.

Response:

(a) Yukon Electrical is aware of one example in 1998 where the YUB ordered the creation of a deferral account related to the sales of Yukon Energy to the Faro mine site under Rate Schedule 34. In Board Order 1998-5, the Board stated:

> All revenue derived from Rate Schedule 34, less reasonable incremental costs associated with supplying the Faro mine site under this rate schedule, shall be placed in a deferral account for subsequent application to the benefit of customers as directed by the Board.

(b) The requested deferral account neither decreases nor increases the risk faced by Yukon Electrical as compared to its 2008-2009 GRA. This is due to fact that no industrial sales were forecasted as part of Yukon Electrical's 2008-2009 GRA.

UCG-YECL-11

Reference: May 27, 2013 Application, page 3-1

YECL states "*Yukon Electrical was directed in Board Order 2009-2 to capitalize the incremental purchased power costs incurred due to Fish Lake rebuilds in 2008/2009. Consistent with this Order, Yukon Electrical has capitalized the incremental purchase power costs incurred for the period in which Fish Lake Unit #1 was out of service after the catastrophic failure in March 2010.*"

Request:

(a) Please provide details of the incremental purchased power costs incurred when Fish Lake was out of service following the March 2010 failure including if any of these costs are being incurred during the 2013-2015 test period.

(b) Please provide details of when the YUB specifically approved the capitalization of the incremental purchased power costs incurred when Fish Lake was out of service following the March 2010 failure.

Response:

(a) Incremental purchased power costs of $346,000 for 2010, $367,000 for 2011, $402,000 for 2012 and $369,000 for 2013 (forecast) were incurred when Fish Lake was out of service following the March 2010 failure.

(b) The YUB has not specifically approved the capitalization of the incremental purchased power costs incurred since Fish Lake Unit #1 went out of service following the March 2010 failure. Yukon Electrical is requesting these amounts be approved as part of this Application.

UCG-YECL-12

Reference: May 27, 2013 Application, page 3-2

YECL states "*The cost of purchase power in this Application is based on Yukon Energy's rates that are currently in place for primary energy and secondary sales and are outlined on Schedule 3.1, lines 6 and 7. These rates do not include any adjustment to the rates associated with Yukon Energy's applied for but not yet approved Energy Reconciliation Adjustment (ERA). Any increases or decreases to these rates for 2013 and thereafter will be flowed through to Yukon Electrical's customers.*"

Request:

(a) Please confirm YECL's understanding that the steps that YEC included in its 2012-2013 General Rates Application to update the Energy Reconciliation Adjustment and reactivate it effective January 1, 2012 were not approved by the YUB in its Order 2013-01 issued March 25, 2013.

(b) Please identify YEC's current application for the Energy Reconciliation Adjustment that has not yet been addressed by the YUB.

(c) Please explain how "any increases or decreases to these rates for 2013 and thereafter will be flowed through to Yukon Electrical's customers".

Response:

(a) Confirmed.

(b) It is Yukon Electrical's understanding that Yukon Energy's 2012-2013 GRA proposed Energy Reconciliation Adjustment has not been approved. In Board Order 2013-03, the Board stated:

> The Board notes that the revised DCF proposal was not filed jointly by YEC and YECL and that there was not a joint recommendation by the companies on how to amend the wording regarding the ERA in Rate Schedule 42. The Board considers that the revised DCF proposal has not been tested in a proceeding. Given the foregoing, the Board does not approve the revised DCF proposal filed in

YEC's 2012-13 GRA compliance filing. Consequently, the Board will not allow any changes regarding 2012 and the effects of any DCF proposal.

YEC may file a future revised DCF proposal and ERA application. The Board prefers a joint filing from YEC and YECL. However, if agreement cannot be reached, a filing in which the companies state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each company on those aspects they disagree upon is acceptable. The filing must also address the concerns raised in Board Order 2013-01 Attachment A: Reasons for Decision. This future revised DCF proposal and ERA application will be separate from the compliance filing directed in this order.

(c) The total impact of any increases or decreases to these rates for 2013 and thereafter would be followed through to customers through a Board approved Rider.

UCG-YECL-14

Reference: May 27, 2013 Application, page 4-1

YECL states "*The forecast fuel cost increase of $974,000 in 2013 is mainly due to the inclusion of the Rider F fuel rider in base rates for the test period. Prior to 2013, Yukon Electrical recovered the difference between the forecast 2009 fuel rates and the current fuel rate using Rider F.*"

May 27, 2013 Application, page 12-2

YECL states "*The Fuel Adjustment Rider, Rider F, will remain in place, to recover diesel fuel cost variances. It will be adjusted as required by the current Rider F fuel cost recovery process.*"

Request:

(a) Please explain what YECL is doing with respect to "the inclusion of the Rider F fuel rider in base rates for the test period" if the Rider F is supposed to be continued as a rate rider.

(b) Please provide details of the YUB order that allows YECL to include the Rider F fuel rider in base rates.

Response:

(a) Consistent with past practice, this application is updating the forecast price of diesel for the test period of January 1, 2013 through to December 31, 2015. These updated fuel prices (as shown on Schedule 4.2 Line 1-7, for the 2013-2015 test years) are used as the price input to determine the forecast fuel expense. Once fuel prices are approved as part of an overall decision on this Application, Yukon Electrical will incorporate them into its Rider F calculations January 1, 2013 forward.

(b) As part of this Application, Yukon Electrical is requesting a Fuel Price Flow Through Deferral. Assuming this deferral is approved by the Board, Yukon Electrical will seek to recover / refund differences between forecast and actual fuel prices via Rider F or other method approved by the Board.

UCG-YECL-18

Reference: May 27, 2013 Application, page 4-2

Regarding diesel fuel costs, YECL states "*Price forecasts for each community are based on the current prices in place for diesel fuel at February 2013.*"

Request:

(a) Please provide details of the source for these diesel fuel prices.

(b) Please update Schedule 4.2 with the most recent diesel fuel prices and provide details of the sources for these prices.

Response:

(a) The source for these diesel fuel prices is the actual February 2013 delivered fuel expense price from fuel suppliers. This is a weighted price based on a First-in First-out inventory basis. Air North is Yukon Electrical's fuel supplier for Old Crow and Suncor Energy Products Partnership supplies fuel to all other communities.

(b) Please refer to UCG-YECL-18(b) Attachment 1. The source for these diesel fuel prices is the actual June 2013 delivered fuel expense price from fuel suppliers. This is a weighted price based on a First-in First-out inventory basis.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Fuel Information

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
	Average Cost (in cents per litre)											
1	Watson Lake		98.91	67.52	75.93	95.88	97.11	96.44	96.44	96.44	87.48	87.48
2	Beaver Creek		101.03	82.28	87.68	109.34	112.59	112.11	112.11	112.11	81.52	81.52
3	Destruction Bay		101.69	80.97	88.14	108.85	112.38	111.44	111.44	111.44	83.13	83.13
4	Old Crow		200.30	164.20	171.70	189.16	214.70	223.60	223.60	223.60	193.41	193.41
5	Pelly Crossing (Standby as of 2009)		106.10	-	-	-	-	-	-	-	89.33	89.33
6	Swift River		105.26	73.83	80.66	97.08	104.01	107.21	107.21	107.21	92.44	92.44
7	Standby Units		62.63	91.21	95.93	105.22	95.29	89.56	89.56	89.56	70.00	70.00
	Generation (MWh)											
8	Watson Lake		14,146	13,940	13,992	14,357	15,024	15,085	15,261	15,267	14,431	14,593
9	Beaver Creek		1,856	1,874	1,917	1,981	1,897	1,800	1,832	1,834	2,021	2,115
10	Destruction Bay		1,768	1,771	1,766	1,862	1,996	1,826	1,860	1,862	1,722	1,741
11	Old Crow		1,820	1,904	1,903	2,067	2,136	2,083	2,114	2,114	2,005	2,029
12	Pelly Crossing		2,203	-	-	-	-	-	-	-	1,863	11
13	Swift River		272	265	189	220	233	263	267	268	278	326
14	Standby Units		158	213	72	446	25	70	70	70	44	44
15		S.4.1 L.1	22,223	19,967	19,839	20,933	21,310	21,127	21,405	21,415	22,364	20,858
16	Net Heat Rate (kWh/litre)											
17	Watson Lake		3.82	3.81	3.85	3.74	3.80	3.78	3.78	3.78	3.82	3.82
18	Beaver Creek		3.57	3.62	3.63	3.48	3.52	3.59	3.59	3.59	3.56	3.56
19	Destruction Bay		3.29	3.58	3.44	3.56	3.68	3.58	3.58	3.58	3.41	3.41
20	Old Crow		3.43	3.40	3.62	3.58	3.45	3.60	3.60	3.60	3.56	3.56
21	Pelly Crossing		3.05	-	-	-	-	-	-	-	3.62	3.62
22	Swift River		2.96	2.99	2.51	2.73	2.77	2.79	2.79	2.79	2.99	2.99
23	Standby Units		3.00	3.00	3.00	3.35	1.50	3.02	3.02	3.02	3.50	3.50
24	Litres Consumed ('000s)											
25	Watson Lake		3,726	3,695	3,673	3,791	3,957	3,988	4,034	4,036	3,778	3,820
26	Beaver Creek		513	515	526	569	539	502	511	512	567	594
27	Destruction Bay		521	483	498	523	542	510	520	520	505	510
28	Old Crow		523	541	514	584	618	578	587	587	562	569
29	Pelly Crossing		644	-	-	-	-	-	-	-	514	3
30	Swift River		92	88	74	81	84	94	96	96	93	109
31	Standby Units		67	87	25	133	17	20	20	20	13	13
32		S.4.1 L.3	6,086	5,409	5,311	5,681	5,757	5,692	5,767	5,770	6,032	5,618

UCG-YECL-19

Reference: May 27, 2013 Application, page 4-2

YECL states "*Yukon Electrical is proposing to continue the deferral for fuel prices for the 2013-2015 test period but is requesting a change in the methodology for calculating the deferral for fuel used in Watson Lake. As a result of the conversion of the diesel units in Watson Lake to bi-fuel (diesel and LNG) beginning in the fall of 2013, generation with be based on a variable mix of diesel and LNG. This means that the forecast plant efficiency cannot be determined at this time. In order to address this issue, Yukon Electrical is requesting to use the actual equivalent diesel litres used as opposed to derived litres that are based on a forecast plant efficiency to arrive at the fuel deferral amount for Watson Lake. For all other locations, the calculation of the fuel price deferral would remain unchanged from that previously approved.*"

Request:

(a) Please confirm YECL's understanding that the Fuel Adjustment Rider & Deferred Fuel Price Variance policy (Rider F - most recently approved by the YUB in February 2012) is related to "deferring, monitoring, collecting and remitting fuel price variance amounts for diesel fuel consumed to generate electricity".

(b) Please provide details of YECL's application to the YUB regarding changing the Fuel Adjustment Rider & Deferred Fuel Price Variance policy to account for fuel prices that are not associated with diesel fuel.

(c) Please provide details of efforts by YECL to get the Yukon government to change Section 8 of the Rate Policy Directive Order in Council 1995/90 that provides for fuel price adjustments and sets out that the Board must permit YEC and YECL to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to reflect fluctuations in the prices for diesel fuel, without the requirement for specific application to and approval of the Board.

(d) Please confirm the identity and qualifications of the expert witness that YECL will put forward to speak to the industry standard conversion factors for LNG that YECL has included in its Application.

(e) Please describe details of the analysis of renewable energy alternatives that were considered in lieu of the LNG option.

(f) Has YECL had any discussions with the Yukon government regarding the development and use of natural gas deposits in the Yukon for electricity generation?

Response:

(a) Confirmed as the only fuel being used for generation by Yukon Electrical and Yukon Energy at that point in time was diesel.

(b) Yukon Electrical believes it is premature at this time to make application to the YUB regarding changing the Fuel Adjustment Rider & Deferral Price Variance Policy for the inclusion of LNG. This application contains all the necessary information for the review and testing of Yukon Electrical's proposed Fuel Price Flow Through deferral and the requested changes relating to the burning of diesel as well as LNG in Watson Lake. Once the Board has ruled on this requested deferral as part of this application, Yukon Electrical and Yukon Energy can file an updated policy that reflects the decision of the YUB.

(c) Yukon Electrical has not made any effort to get the Yukon government to change Section 8 of the Rate Policy Directive Order in Council 1995/90 that provides for fuel price adjustments and sets out that the Board must permit YEC and Yukon Electrical to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to reflect fluctuations in the prices for diesel fuel, without the requirement for specific application to and approval of the Board. That being said, Yukon Electrical is requesting a deferral for its fuel costs as part of this Application with the Yukon Utilities Board.

(d) The conversion of liters of liquefied natural gas (LNG) to diesel liters equivalent (DLE) is an industry accepted practice. As such, Yukon Electrical does not propose to provide an expert witness to participate at the hearing.

The industry accepted formula for conversion is:

LNG Volume [Diesel Litres Equivalent] = LNG Volume [Liters LNG] * Energy Content of LNG [MJ/L] / Energy Content of Diesel [MJ/L]

The energy density, the ratios of Higher and Lower Heating Value for both LNG and diesel, and the density of diesel can be found from source: U.S. Department of Energy, Center for Transportation Analysis, Biomass Energy Data Book: Edition 4. Appendix A, Conversions: Lower and Higher Heating Values of Gas, Liquid and Solid Fuels. Retrieved May 15, 2013, from http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_S olid_Fuels.pdf.

The Higher Heating Value of LNG is provided by FortisBC Energy Inc. The estimated density of LNG can be found from source: The International Group of Liquefied Natural Gas Importers, LNG Information Paper No.1. Retrieved July 24, 2013 from http://www.giignl.org/fileadmin/user_upload/pdf/LNG_Safety/1-LNG_Basics_8.28.09_Final_HQ.pdf

(e) A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed with a levelized cost of electricity estimated at 50 cents/kWh. Yukon Electrical is participating in a hydroelectric study to provide long-term renewable electricity for the Watson Lake electrical system. Yukon Electrical is participating in a geothermal energy study as an additional long term renewable alternative.

(f) No.

UCG-YECL-23

Reference: May 27, 2013 Application, page 7-1

YECL states "*The impact of the depreciation study is a significant increase in forecast depreciation expense primarily due to the request for reinstatement of a provision for future removal and site restoration in depreciation rates.*"

Request:

(a) Please provide a table that compares YECL's current and proposed depreciation rates with the depreciation rates allowed for Yukon Energy Corporation for similar assets. Include an analysis of the impact that any differences have on the depreciation expense forecast by YECL for the 2013-2015 test period.

(b) Please explain how YECL treated the difference between the depreciation expense allowed to be recovered in rates in 2009 and the depreciation expense identified as incurred in 2010, 2011 and 2012.

(c) Please explain the significant change in amortization of differences between 2009 allowed and the forecast for 2013-2015.

(d) Please provide schedules 7.2, 7.3 and 7.4 showing depreciation expense at existing rates.

(e) Please provide details on the impact of the proposed change in depreciation expense on the overall revenue requirement for 2013, 2014 and 2015 including the change in rate base and return.

Response:

(a) In YEC's 2012-2013 GRA, YEC provided a response to YECL-YEC-1-55(a) Attachment 1, which showed Depreciation Expense and related Rate (%). A large number of accounts had a Note of "n/a" which was stated to reflect asset classes which KPMG reviewed, however a change was deemed unnecessary. In a further information response to YECL-YEC-1-61(d), YEC provided its previous Depreciation Study which was conducted on assets as of December 31, 2003. To the best of Yukon Electrical's knowledge, Table 1 of

YEC's December 31, 2003 Depreciation Study shows the Depreciation Rates that were approved for YEC and, in the vast majority of accounts are still valid for YEC. To the best of Yukon Electrical's knowledge, YEC does not update its depreciation rates to reflect subsequent capital activity of additions and retirements which can have a significant change in the resulting depreciation rates. In Yukon Electrical's opinion, the comparison of depreciation rates from a study that was done based on asset balances as of the end of 2003 (and not updated with subsequent capital activity) to Yukon Electrical's current depreciation study, which developed depreciation parameters as of the end of 2011 and was updated to reflect forecast capital activity, is an inappropriate comparison. Yukon Electrical has nevertheless provided its understanding of YEC's current depreciation rates to Yukon Electrical's proposed depreciation rates in UCG-YECL-23(a) Attachments 1 to 3. The difference in depreciation expense between Yukon Electrical's proposed depreciation rates compared to Yukon Electrical's best understanding of YEC's current depreciations rates is a decrease to Yukon Electrical's forecast depreciation expense of $1.293M, $1.537M, $1.871M for 2013, 2014, and 2015, respectively. The majority of this change is likely due to Yukon Electrical's proposed reinstatement of net salvage in its depreciation rates.

(b) The amount by which actual depreciation expense incurred was higher for each year from 2010-2012 than the depreciation expense allowed to be recovered in rates in 2009 was a reduction to Yukon Electrical's earnings for each of those years.

(c) Please refer to YUB-YECL-83(b). The amortization of differences is developed using the forecast life and net salvage parameters for each fixed asset account. Using the forecast life and net salvage parameters assumes that these parameters have been in existence since day 1 for each fixed asset account and determines a calculated accrued depreciation to the date of the depreciation study. This calculated accrued depreciation is then compared to the actual booked accumulated depreciation. If the booked value is greater than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account, as an annual provision for true-up, resulting in an annual depreciation expense decrease. Similarly, if the booked value is less than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account resulting in an annual depreciation expense increase. Thus, the difference between the previous depreciation study amount

of ($382,000) to the current depreciation study amount of $71,000 reflects depreciation parameter forecast changes.

(d) Please refer to YUB-YECL-83(a) Attachment 1.

(e) Please refer to UCG-YECL-23(e) Attachment 1 for the impact of the change in depreciation parameters as a result of updating the depreciation study, as well as the impact of the reinstatement of a provision for net salvage in depreciation rates, on revenue requirement, rate base and return on rate base. Please note that the requested reinstatement of a provision for net salvage in depreciation rates results in a reduction in rate base and, as a result, a lower return on rate base.

The Yukon Electrical Company Limited
2013 Depreciation Rates
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Account	Description	Life Parameter	NS Parameter	Composite Rate	2012 Original Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.40%	262,557.87	1.39%		(2,652)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.40%	2,374,620.82	0.97%		(33,957)
42500	Generators	R3-85 / 2052	-10%	2.68%	2,685,841.06	1.18%		(40,288)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.58%	157,864.16		2.22%	(568)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.07%	68,656.70		3.33%	(508)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.50%	177,646.92	1.39%		(3,748)
44401	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.56%	193,505.60		4.00%	851
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.82%	586,223.70	2.50%		(7,738)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	129,917.54		2.22%	(1,000)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.84%	48,460.21		3.33%	237
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.09%	167,738.94	1.39%		(2,852)
44402	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.60%	139,911.46		4.00%	560
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.80%	419,543.17	2.50%		(5,454)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.03%	101,158.38		2.22%	(819)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.93%	10,337.91		3.33%	41
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	3.03%	42,281.93	1.39%		(693)
44403	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2023	-20%	5.30%	185,288.48		4.00%	(2,409)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	7.05%	497,404.95	2.50%		(22,632)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	4.77%	272,311.04		2.22%	(6,944)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	4.82%	24,406.04		3.33%	(364)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.21%	608,472.09	1.39%		(11,074)
44404	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.24%	498,928.74	2.50%		(8,681)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.80%	91,707.86		2.22%	(532)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.63%	5,425.93		3.33%	38
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.79%	218,250.71	1.39%		(3,056)
44405	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.60%	957,181.53		4.00%	3,829
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.22%	663,170.33	2.50%		(11,407)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.79%	119,365.14		2.22%	(680)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.58%	126,010.04		3.33%	945
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.57%	48,891.66	1.39%		(577)
44406	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2033	-20%	3.56%	191,354.03		4.00%	842
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.97%	498,983.00	2.50%		(7,335)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.81%	403,751.15		2.22%	(6,420)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.57%	68,488.84		3.33%	(164)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.25%	264,971.01	1.39%		(4,928)
44407	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.57%	87,965.86		4.00%	378
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.71%	201,226.65	2.50%		(2,435)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	136,596.48		2.22%	(1,079)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.81%	12,646.75		3.33%	66
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.08%	247,965.51	1.39%		(4,191)
44408	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.59%	135,110.10		4.00%	554
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.01%	17,032.82	2.50%		(87)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.87%	43,969.44		2.22%	(286)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.97%	97,465.09		3.33%	351
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.80%	22,503.27	1.39%		(317)
44409	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.53%	149,400.56		4.00%	702
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.47%	244,095.95	2.50%		(4,809)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	58,519.97		2.22%	(462)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.78%	7,891.83		3.33%	43

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2012 Original Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.44%	78,847.51	1.39%		(1,616)
44410	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.63%	112,552.65		4.00%	416
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.94%	790,518.99	2.50%		(11,383)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.14%	119,706.46		2.22%	(1,101)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.86%	75,757.42		3.33%	356
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.66%	359,392.86	1.39%		(4,564)
44411	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2113	-20%	3.60%	805,271.40		4.00%	3,221
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.04%	2,416,037.94	2.50%		(37,207)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.81%	573,096.39		2.22%	(3,381)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.76%	237,902.83		3.33%	1,356
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.52%	1,227.46	1.39%		(26)
44499	Fuel Holders, Producers & Acc. Equipmer	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.23%	430,919.65	2.50%		(7,455)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.13%	26,413.95		2.22%	(240)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.86%	78,852.20		3.33%	371
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.25%	1,384,421.27	1.85%		(5,538)
Distribution								
47100	Land Rigths	R3-75	0%	1.51%	1,330,642.34	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	34,182,587.39		2.86%	(458,047)
47400	Overhead Conductor	R4-45	-80%	4.16%	22,281,820.39		2.50%	(369,878)
47410	Overhead Services	R3-45	-10%	2.57%	2,978,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	22,879,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.87%	3,097,260.23		2.50%	(11,460)
47610	Meters	L0-15	0%	7.65%	1,983,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	7.31%	68,140.35		3.33%	(2,712)
47710	Substation Equipment	R4-40	-10%	2.75%	3,131,073.05	1.82%		(29,119)
47810	Street Lights & Signal Systems	R3-30	-10%	3.77%	9,599,523.57		2.50%	(121,914)
47820	Sentinel Lights	R2-23	0%	2.99%	284,738.28		3.33%	968
47910	Line Transformers	R3-45	-10%	2.66%	28,161,770.91		2.50%	(45,059)
General Plant								
48200	Structures and Improvements	L3-40	0%	2.63%	3,646,079.85	1.82%		(29,533)
48300	Office Furniture and Equipment	SQ-15	0%	5.70%	193,625.00		5.00%	(1,355)
48320	Computer Equipment and Accessories	SQ-5	0%	18.73%	47,030.54		16.29%	(1,148)
48400	Transportation Equipment - Category 1	L0-12	25%	6.44%	2,953,744.17		8.15%	50,656
48500	Tools and Instruments	SQ-15	0%	6.33%	843,412.27		5.00%	(11,217)
48600	Communication Equipment	SQ-15	0%	5.50%	938,160.01		5.00%	(4,691)
48820	Houses	R3-40	-10%	2.93%	474,681.26		2.83%	(475)
					161,520,822.70			(1,292,799)

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2013 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.79%	459,557.87	1.39%		(6,434)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.60%	4,159,620.82	0.97%		(67,802)
42500	Generators	R3-85 / 2052	-10%	2.77%	4,696,841.06	1.18%		(74,680)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.87%	276,864.16		2.22%	(1,800)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.46%	120,656.70		3.33%	(1,363)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.52%	259,646.92	1.39%		(5,530)
44401	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	282,505.60		4.00%	1,158
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.22%	1,186,223.70	2.50%		(20,403)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.10%	189,917.54		2.22%	(1,671)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.92%	70,460.21		3.33%	289
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.06%	167,738.94	1.39%		(2,801)
44402	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	139,911.46		4.00%	574
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.72%	419,543.17	2.50%		(5,118)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	101,158.38		2.22%	(799)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.90%	10,337.91		3.33%	44
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	4.84%	55,281.93	1.39%		(1,907)
44403	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2023	-20%	6.70%	240,288.48		4.00%	(6,488)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	7.03%	497,404.95	2.50%		(22,532)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	5.87%	353,311.04		2.22%	(12,896)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	5.88%	31,406.04		3.33%	(801)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.17%	608,472.09	1.39%		(10,831)
44404	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.17%	498,928.74	2.50%		(8,332)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.77%	91,707.86		2.22%	(504)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.61%	5,425.93		3.33%	39
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.94%	264,250.71	1.39%		(4,096)
44405	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.60%	1,159,181.53		4.00%	4,637
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.17%	663,170.33	2.50%		(11,075)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.87%	144,365.14		2.22%	(938)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.66%	153,010.04		3.33%	1,025
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.54%	48,891.66	1.39%		(562)
44406	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2033	-20%	3.54%	191,354.03		4.00%	880
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.91%	498,983.00	2.50%		(7,036)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.78%	403,751.15		2.22%	(6,299)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.55%	68,488.84		3.33%	(151)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.19%	268,971.01	1.39%		(4,841)
44407	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.56%	88,965.86		4.00%	391
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	204,226.65	2.50%		(2,349)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	138,596.48		2.22%	(1,067)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.80%	12,646.75		3.33%	67
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.07%	252,965.51	1.39%		(4,250)
44408	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	137,110.10		4.00%	562
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	2.95%	17,032.82	2.50%		(77)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.85%	44,969.44		2.22%	(283)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.95%	99,465.09		3.33%	378
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.78%	22,503.27	1.39%		(313)
44409	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.51%	149,400.56		4.00%	732
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.46%	274,095.95	2.50%		(5,372)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	58,519.97		2.22%	(451)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.77%	7,891.83		3.33%	44

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	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.36%	78,847.51	1.39%		(1,553)
44410	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.62%	112,552.65		4.00%	428
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.86%	790,518.99	2.50%		(10,751)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.11%	119,706.46		2.22%	(1,065)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.85%	75,757.42		3.33%	364
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.79%	433,392.86	1.39%		(6,068)
44411	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2113	-20%	3.61%	972,271.40		4.00%	3,792
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.27%	4,140,037.94	2.50%		(73,279)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.87%	692,096.39		2.22%	(4,499)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.77%	285,902.83		3.33%	1,601
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.40%	1,227.46	1.39%		(25)
44499	Fuel Holders, Producers & Acc. Equipme	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.52%	1,355,919.65	2.50%		(27,390)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.10%	26,413.95		2.22%	(232)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.83%	78,852.20		3.33%	394
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.25%	1,384,421.27	1.85%		(5,538)
Distribution								
47100	Land Rigths	R3-75	0%	1.50%	1,432,642.34	unkown	unkown	
47200	Demand Side Management	SQ-10	0%	10.00%	481,000.00	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	36,821,587.39		2.86%	(493,409)
47400	Overhead Conductor	R4-45	-80%	4.16%	23,984,820.39		2.50%	(398,148)
47410	Overhead Services	R3-45	-10%	2.58%	3,206,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	24,628,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.86%	3,334,260.23		2.50%	(12,003)
47610	Meters	L0-15	0%	8.09%	2,583,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	7.13%	68,140.35		3.33%	(2,589)
47710	Substation Equipment	R4-40	-10%	2.75%	3,370,073.05	1.82%	2.22%	(31,342)
47810	Street Lights & Signal Systems	R3-30	-10%	3.75%	9,995,523.57		2.50%	(124,944)
47820	Sentinel Lights	R2-23	0%	2.93%	284,738.28		3.33%	1,139
47910	Line Transformers	R3-45	-10%	2.65%	30,305,770.91		2.50%	(45,459)
								-
General Plant								-
48200	Structures and Improvements	L3-40	0%	2.67%	4,777,079.85	1.82%		(40,605)
48300	Office Furniture and Equipment	SQ-15	0%	6.67%	199,883.83		5.00%	(3,338)
48320	Computer Equipment and Accessories	SQ-5	0%	20.00%	42,745.55		16.29%	(1,586)
48400	Transportation Equipment - Category 1	L0-12	25%	6.59%	3,512,744.17		8.15%	54,974
48500	Tools and Instruments	SQ-15	0%	6.67%	860,610.61		5.00%	(14,372)
48600	Communication Equipment	SQ-15	0%	6.67%	658,805.95		5.00%	(11,002)
48820	Houses	R3-40	-10%	2.91%	474,681.26		2.83%	(380)
					182,048,640.82			(1,537,231.00)

The Yukon Electrical Company Limited
2015 Depreciation Rates
Based on 2013/2015 GTA

Account	Description	Life Parameter	NS Parameter	Composite Rate	2014 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.91%	626,557.87	1.39%		(9,524)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.68%	5,666,620.82	0.97%		(96,899)
42500	Generators	R3-85 / 2052	-10%	2.82%	6,394,841.06	1.18%		(104,875)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.97%	376,864.16		2.22%	(2,826)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.51%	164,656.70		3.33%	(1,943)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.43%	259,646.92	1.39%		(5,297)
44401	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.58%	282,505.60		4.00%	1,187
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.33%	1,686,223.70	2.50%		(30,858)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.07%	189,917.54		2.22%	(1,614)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.89%	70,460.21		3.33%	310
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.03%	167,738.94	1.39%		(2,751)
44402	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.58%	139,911.46		4.00%	588
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	419,543.17	2.50%		(4,825)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	101,158.38		2.22%	(779)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.88%	10,337.91		3.33%	47
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	6.94%	79,281.93	1.39%		(4,400)
44403	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2023	-20%	8.52%	346,288.48		4.00%	(15,652)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	9.53%	1,097,404.95	2.50%		(77,148)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	7.32%	509,311.04		2.22%	(25,975)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	7.33%	45,406.04		3.33%	(1,816)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.14%	608,472.09	1.39%		(10,648)
44404	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.11%	498,928.74	2.50%		(8,033)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.75%	91,707.86		2.22%	(486)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.59%	5,425.93		3.33%	40
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.38%	564,250.71	1.39%		(11,229)
44405	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.65%	2,473,181.53		4.00%	8,656
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.35%	1,163,170.33	2.50%		(21,519)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.15%	308,365.14		2.22%	(2,868)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.90%	326,010.04		3.33%	1,402
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.51%	48,891.66	1.39%		(548)
44406	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2033	-20%	3.52%	191,354.03		4.00%	918
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.84%	498,983.00	2.50%		(6,686)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.76%	403,751.15		2.22%	(6,218)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.53%	68,488.84		3.33%	(137)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.19%	285,971.01	1.39%		(5,147)
44407	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.56%	94,965.86		4.00%	418
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	217,226.65	2.50%		(2,498)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	147,596.48		2.22%	(1,136)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.81%	13,646.75		3.33%	71
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.24%	340,965.51	1.39%		(6,308)
44408	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.61%	185,110.10		4.00%	722
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.36%	23,032.82	2.50%		(198)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.98%	60,969.44		2.22%	(463)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.98%	134,465.09		3.33%	471
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.76%	22,503.27	1.39%		(308)
44409	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.50%	149,400.56		4.00%	747
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.43%	274,095.95	2.50%		(5,290)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.96%	58,519.97		2.22%	(433)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.75%	7,891.83		3.33%	46

The Yukon Electrical Company Limited
2015 Depreciation Rates
Based on 2013/2015 GTA

Account	Description	Life Parameter	NS Parameter	Composite Rate	2014 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.29%	78,847.51	1.39%		(1,498)
44410	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.61%	112,552.65		4.00%	439
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.78%	790,518.99	2.50%		(10,119)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.08%	119,706.46		2.22%	(1,029)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.83%	75,757.42		3.33%	379
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.91%	555,392.86	1.39%		(8,442)
44411	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2113	-20%	3.61%	1,246,271.40		4.00%	4,860
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.26%	4,340,037.94	2.50%		(76,385)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.95%	887,096.39		2.22%	(6,476)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.78%	364,902.83		3.33%	2,007
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.32%	1,227.46	1.39%		(24)
44499	Fuel Holders, Producers & Acc. Equipmer	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.50%	1,355,919.65	2.50%		(27,118)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.08%	26,413.95		2.22%	(227)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.81%	78,852.20		3.33%	410
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.24%	1,384,421.27	1.85%		(5,399)
Distribution								
47100	Land Rigths	R3-75	0%	1.50%	1,545,642.34	unkown	unkown	
47200	Demand Side Management	SQ-10	0%	10.00%	1,003,000.00	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	39,744,587.39		2.86%	(532,577)
47400	Overhead Conductor	R4-45	-80%	4.16%	25,874,820.39		2.50%	(429,522)
47410	Overhead Services	R3-45	-10%	2.58%	3,459,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	26,568,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.86%	3,597,260.23		2.50%	(12,950)
47610	Meters	L0-15	0%	7.40%	2,633,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	8.08%	1,327,140.35		3.33%	(63,039)
47710	Substation Equipment	R4-40	-10%	2.75%	3,636,073.05	1.82%	2.22%	(33,815)
47810	Street Lights & Signal Systems	R3-30	-10%	3.76%	10,940,523.57		2.50%	(137,851)
47820	Sentinel Lights	R2-23	0%	2.87%	284,738.28		3.33%	1,310
47910	Line Transformers	R3-45	-10%	2.65%	32,676,770.91		2.50%	(49,015)
								-
General Plant								-
48200	Structures and Improvements	L3-40	0%	2.66%	5,098,079.85	1.82%		(42,824)
48300	Office Furniture and Equipment	SQ-15	0%	6.67%	239,134.61		5.00%	(3,994)
48320	Computer Equipment and Accessories	SQ-5	0%	20.00%	38,278.66		16.29%	(1,420)
48400	Transportation Equipment - Category 1	L0-12	25%	6.98%	4,507,744.17		8.15%	52,965
48500	Tools and Instruments	SQ-15	0%	6.67%	1,021,445.42		5.00%	(17,058)
48600	Communication Equipment	SQ-15	0%	6.67%	650,127.45		5.00%	(10,857)
48820	Houses	R3-40	-10%	2.89%	474,681.26		2.83%	(285)
					204,822,581.02			(1,870,583.68)

	As Filed	Using 2008/2009 Approved Depreciation Parameters	Using 2013/2015 Proposed Depreciation Parameters - No Net Salvage
2013			
Revenue Requirement	54,956	52,885	52,239
Rate Base	72,329	73,078	73,312
Return on Rate Base	5,308	5,364	5,382
2014			
Revenue Requirement	58,707	56,643	55,988
Rate Base	86,063	88,354	89,075
Return on Rate Base	6,255	6,420	6,473
2015			
Revenue Requirement	61,187	58,880	58,343
Rate Base	96,812	100,830	102,028
Return on Rate Base	7,003	7,292	7,378

UCG-YECL-24

Reference: May 27, 2013 Application, Section 7, Attachment 2

Mr. Kennedy states that "*many depreciation studies completed by Gannett Fleming have developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal.*"

Request:

(a) Please identify utilities comparable to YECL that have been allowed to include net salvage estimates within their current depreciation rates.

(b) Please provide details of regulator decisions related to the Gannett Fleming's proposed provisions relating to the recovery of costs of removal.

(c) Mr. Kennedy notes that Gannett Fleming developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal for Enbridge Consumers Gas in a 2012 Application to the Ontario Energy Board. How does this compare to Enbridge's application filed in June 2013 (EB-2012-0459) to change depreciation rates to reduce the annual amount for future site restoration costs and to implement a rate rider to return to ratepayers over a 5 year period more than $250 million previously over-collected in depreciation rates for site restoration costs and explain why Gannett's previously recommended depreciation rates were too high?

(d) Other than Enbridge, is Mr. Kennedy aware of any other utility that has had to refund over-collections of site recovery costs to ratepayers?

Response:

(a) A listing of utilities (that Yukon Electrical and Mr. Kennedy are aware of) that include net salvage within their depreciation rates is provided below:

- ENMAX Power Corporation (AUC Decision 2009-084)
- FortisAlberta Inc. (AUC Decision 2011-509)

- ATCO Electric (AUC Decision 2011-134)
- Manitoba Hydro (through 2014) (Manitoba PUB Order 43/13)
- Nova Scotia Power (Decision #NSUARB-NSPI-P-891)
- Newfoundland Power Inc. (Order No. P.U.13 (2013)
- Northland Utilities (NWT) Limited (PUB Decision 17-2011)
- Northland Utilities (Yellowknife) Ltd (PUB Decision 13-2011)

While the above listing is specific to electric distribution systems, the following is a list of other regulated Canadian utilities that include net salvage in the depreciation rate calculations:

- FortisBC Energy Inc. (BCUC Application 3698627)
- AltaLink LP (AUC Decision 2011-453)
- ATCO Gas (AUC Decision 2011-450)
- AltaGas Utilities Inc. (AUC Decision 2012-091)
- SaskEnergy Inc. (2007 Depreciation Study filing)
- CentraGas Manitoba (through 2014) (2012/13 and 2013/14 General Rate Application)
- Enbridge Gas Distribution (OEB Decision EB 2011-0345)
- Union Gas (OEB Decision EB-2007-0606)
- Gaz Metro (La Regie de L'Energie Decision R-3752-2011)
- Gazifere (La Regie de L'Energie Decision R-3724-2010)
- TransCanada Pipelines (NEB Decision RH-003-2011)

(b) Gannett Fleming does not understand what is meant by "provide details of regulator decisions." Please refer to part (a) for references to the applicable applications or Decisions. Many of these utilities have been allowed to include net salvage estimates in their depreciation rates for an extended period of time and as such, it would be difficult to provide details of the decision that first approved that treatment with a reasonable amount of effort and in the time allowed to respond to these information requests.

(c) This request is asking for specific comment on an application that is currently before the Ontario Energy Board for which Mr. Kennedy has been retained by Enbridge Consumers Gas to provide expert opinion. Mr. Kennedy is contractually precluded from disclosing any information with regard to the Enbridge Consumers Gas depreciation position that is not yet on the public record before the Ontario Energy Board. As such, Mr. Kennedy cannot comment on the reasons for the current over-depreciation position to any extent beyond that disclosed in the June 2013 Enbridge application (Application EB-2012-0459).

(d) True-ups of Accumulated Depreciation variances are part of virtually all depreciation studies conducted in Canada and most studies conducted throughout North America. The true-ups are often embedded in a remaining life calculation (where the net book value as adjusted for salvage is recovered over an estimated remaining life) or through a specific true up calculation (as is done in most Alberta studies and in this current Yukon Electrical application). These true-ups are required due to a number of factors, including variances caused by net salvage estimates being different than actual costs of retirement of assets.

Mr. Kennedy is not aware of any circumstances similar to the Enbridge Consumers Gas circumstance.

UCG-YECL-25

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 18

Mr. Kennedy states that "*investor-owned utilities generally all seek to incorporate the recovery of costs of removal in their revenue requirements through depreciation expense."*

Request:

Please provide details of any utilities that either do not recover costs of removal through depreciation rates or use another mechanism to recover these costs.

Response:

Mr. Kennedy is aware of the following Canadian utilities that use an alternative mechanism for the recovery of costs of retirement:

- BC Hydro – Was ordered by the BCUC to draw down their current FRSR fund and then to expense costs of retirement in year of occurrence after the fund is drawn down to zero.

- FortisBC Inc. – Do not include any costs of removal in the depreciation calculations, but charge actual costs of removal to the accumulated depreciation account and recover the accumulated depreciation variance caused by this practice over the composite remaining life of each account.

- SaskPower – Charges costs of retirement to income (and to the revenue requirement) in the year of occurrence.

- Manitoba Hydro – Is recovering net salvage in the depreciation rates over its current test period, but has indicated that in future test years when IFRS is implemented the net salvage will be recovered in year of occurrence.

- Centra Gas Manitoba – Is recovering net salvage in the depreciation rates over their current test period, but have indicated that in future test years when IFRS is implemented the net salvage will be recovered in year of occurrence.

- Ontario Power Generation – Expenses the costs of retirement in year of occurrence (and to the revenue requirement)

- Hydro One – Expenses the costs of retirement in year of occurrence (and to the revenue requirement)

- New Brunswick Power – Distribution and Transmission assets – Does not include any costs of retirement in the depreciation calculations, but charges actual costs of retirement to the accumulated depreciation account and recovers the accumulated depreciation variance caused by this practice over the composite remaining life of each account.

- New Brunswick Power – Generation Assets – Expenses the costs of retirement in year of occurrence (and to the revenue requirement).

- Nalcor – Newfoundland and Labrador Hydro – Expenses the costs of retirement in year of occurrence (and to the revenue requirement).

- Qulliq Power Corporation - Expenses the costs of retirement in the year of occurrence.

UCG-YECL-26

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 18

Mr. Kennedy states that "*While investor-owned utilities will often attempt to avoid differences in the regulated ledgers versus the financial disclosure ledgers, I have noted that there is a greater tolerance to reconcile these differences.*"

Request:

Please provide details of any utilities that do have differences in the regulated ledgers versus the financial disclosure ledgers.

Response:

Mr. Kennedy notes that virtually all regulated utilities will have some differences between the accounting ledgers and the regulated accounting ledgers. However, it is Mr. Kennedy's experience that investor-owned utilities have a larger number of variances caused by other non-depreciation factors and will have an increased number of regulatory deferral accounts or will maintain completely separate ledgers. This has become more apparent as regulated utilities have adopted differing accounting standards (IFRS versus USGAAP, etc.).

With specific regard to depreciation practices, Mr. Kennedy is aware of the following utilities that have indicated a willingness to maintain an increased number of deferral accounts or separate depreciation related accounting ledgers:

- FortisBC Energy Inc.;
- FortisBC Inc.;
- ATCO Electric;
- ATCO Gas;
- ATCO Pipelines;
- FortisAlberta;
- AltaLink LP;
- AltaGas;
- ENMAX Power Corporation;
- Enbridge Consumers Gas;

- Union Gas;
- Newfoundland Power;
- NTPC;
- Northland Utilities (NWT) Ltd;
- Northland Utilities (Yellowknife) Limited; and
- TransCanada Pipelines.

UCG-YECL-27

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 19

Mr. Kennedy states that "*it is my experience that ownership does make a difference in the regulatory and depreciation principles as applied by regulatory authorities throughout Canada.*"

May 27, 2013 Application, Section 7, Attachment 2, page 20

Mr. Kennedy states that "*Canadian regulatory practice over the period since the issuance of YUB Order 2009-2 demonstrates an increased tolerance of allowing crown-owned utilities to follow differing practices with regard to net salvage than investor-owned utilities within the same jurisdiction."*

Request:

(a) Please identify when the Yukon Utilities Board has applied regulatory and depreciation principles differently to YECL and YEC.

(b) Other than in Newfoundland, has any Canadian regulator allowed a differing practice regarding collection of net salvage estimates by a crown-owned utility as compared to an investor-owned utility that deal with the same form of energy?

(c) Does Mr. Kennedy consider Ontario's crown-owned Ontario Power Generation comparable to the gas distribution utilities in Ontario?

(d) Please provide details of where Canadian regulatory practice over the period since the issuance of YUB Order 2009-2 demonstrates an increased tolerance of allowing crown-owned utilities to follow differing practices with regard to net salvage than investor-owned utilities within the same jurisdiction.

(e) Please identify where YECL's circumstances have changed since the February 2009 issuance of Order 2009-2 that would require the reinstatement of negative salvage amounts in depreciation rates.

Response:

(a) Yukon Electrical is aware of two differences between YEC and Yukon Electrical in regards to regulatory and depreciation principles. One notable difference is with respect to the hearing costs reserve. In the case of Yukon Energy, it did not have a Hearing Cost Reserve until its most recent 2012-2013 GRA. Yukon Electrical, however, was ordered to treat its hearing costs as part of a Hearing Cost Reserve since the 1996-1997 GRA. With regard to depreciation practices, it is noted that in YUB Decision 2009-02, the use of Equal Life Group (ELG) procedure was specifically approved for use by Yukon Electrical, despite the argument of YEC which pointed out that they were using the Average Service Life procedure. As such, there is a significant difference in the approved depreciation practices for Yukon Electrical as compared to YEC.

(b) In British Columbia, the BCUC has ordered a differing practice for BC Hydro as compared to the allowed practice for the electric operations of FortisBC Energy Inc. as described in response to UCG-YECL-25.

It is noted that there are only a few circumstances where there is a mix of crown-owned corporations and private investor-owned utilities within the same province in the same energy sector. However, a broader look across Canadian jurisdictions provides a much clearer view of the differences in approaches of crown and investor-owned utilities. Additionally, in a number of provinces where crown and investor-owned utilities exist across varying energy sectors, the differences in approaches are also more apparent.

(c) Mr. Kennedy notes that there are obvious large differences between large hydro and nuclear generation and natural gas distribution utilities. However, there are a number of regulatory similarities between Ontario Power Generation and the natural gas distribution utilities in Ontario as follows:

- Both are regulated by the Ontario Energy Board;
- Both will face very large expenditures related to future removal of facilities;
- Both have a mix of long lived assets and shorter lived technology-based assets.

(d) Please refer to the additional evidence of Larry Edwin Kennedy at pages 6 through 10, and pages 14 through 18 included in Yukon Electrical's Application.

(e) Please refer to the response to information request YEC-YECL-12(a).

UCG-YECL-28

Reference: May 27, 2013 Application, page 8-4

YECL states "*Yukon Electrical, as detailed in the expert evidence prepared by Kathy McShane for the 2008-2009 GRA, shares similar business risk to its affiliate, Northland Utilities (Yellowknife) Limited."*

May 27, 2013 Application, page 8-5

YECL states "*Yukon Electrical continues to face greater business risk than the average Canadian or British Columbia utility.*"

Request:

(a) Please provide the evidence upon which the statement on page 8-5 is based and the qualifications of the individual that undertook this analysis.

(b) With respect to the comparison of YECL relative to the Northland utilities, what evidence exists that Northland is comparable to YECL's current operations and operating environment?

Response:

(a) For purposes of this Application, Yukon Electrical continues to rely on the 2008-2009 expert evidence from Kathy McShane that concluded Yukon Electrical's business risk suggested an equity ratio of 45% - 55% and financial metrics suggested an equity ratio in the upper end of the 47.5% - 52.5% range. Please refer to YUB-YECL-33(b) Attachment 1 for a copy of this expert evidence. To address the issue of the period of time between 2008 and today, Yukon Electrical management completed a review of its business risks in the 2013-2015 test period as compared to the 2008-2009 test period. While most business risks continue to remain consistent with those assessed in 2008, Yukon Electrical has noted a number of areas in market demand and operational costs where business risk has increased modestly since 2008. Please refer to YUB-YECL-31 for further details on its business risk in 2013 as compared to 2008.

(b) For purposes of regulatory efficiency, Yukon Electrical is relying on the evidence provided in the 2008-2009 GRA that stated Yukon Electrical has comparable business risk to Northland as well as Yukon Electrical management's conclusion as part of this Application that nothing material has changed in the period between 2008 and 2013 that would indicate a significant change in the relative risk between Yukon Electrical and Northland Utilities. Please refer to YUB-YECL-31 where Yukon Electrical provides further details on its business risk in 2013 as compared to 2008 as well as YUB-YECL-33(b) where Yukon Electrical provides statistics comparing Yukon Electrical with the Northland companies in 2012.

UCG-YECL-29

Reference: YUB Order 2013-01 - Reasons for Decision, March 25, 2013 Application,

The YUB states on page 50 "*In summary, the Board has determined that the simplified approach is the approach to be used in determining the ROE for utilities under its jurisdiction. The simplified approach was based on the precedence of the BCUC formulaic model. In this proceeding, since recent results of the BCUC model are not available, YEC can use the benchmark results from the AUC model. Therefore, the Board directs YEC in its compliance filing to use an ROE of 8.25 percent."*

May 27, 2013 Application, page 8-3

YECL states that on May 10, 2013, the BCUC issued Order G-75-13 addressing a number of matters including (1) a generic benchmark ROE of 8.75% effective January 1, 2013; (2) a benchmark common equity ratio of 38.5% effective January 1, 2013; and (3) an Automatic Adjustment Mechanism formula for annually setting the ROE starting January 1, 2014. YECL also notes that a second phase of the BCUC GCOC proceeding is now underway which will determine an appropriate risk premium and deemed capital structure for British Columbia utilities that differ in risk from the benchmark utility.

O.I.C. 1995/090

Normal return on equity

2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

Request:

(a) Please confirm YECL's understanding that OIC 1995/90 requires that there only be 0.5% difference between the return on equity allowed to be recovered in rates charged by YECL and YEC.

(b) Please confirm YECL's understanding that the YUB has allowed YEC to incorporate a return on equity of 8.25% into its 2013 rates.

Response:

(a) Not confirmed. OIC 1995/90, as amended by OIC 1998/32, states the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on the equity used to finance their rate base. In the case of Yukon Energy, the Board determined a fair return of 8.75% for each of 2012 and 2013 in Decision 2013-01. This return was based on Yukon Energy's 2012-2013 GRA and the associated evidentiary record. Thereafter, subject to subsection (2) of OIC 1995/90, the Board determined Yukon Energy's awarded return to be 8.25% (8.75% - 0.5%) for each of 2012 and 2013. In the case of Yukon Electrical's 2013-2015 GRA, the Board will award a fair return on the equity used to finance Yukon Electrical's rate base based on Yukon Electrical's Application and the associated evidentiary record. Subsection (2) of OIC 1995/90 is not applicable to Yukon Electrical.

(b) Confirmed.

UCG-YECL-30

Reference: May 27, 2013 Application, page 8-6

YECL states "*Given Yukon Electrical shares similar business risks as compared to its affiliates in the Northwest Territories as well as the increase to the common equity ratio benchmark in British Columbia, Yukon Electrical is requesting to increase its common equity ratio from the current level of 40% to 44% for each of 2013, 2014 and 2015.*"

Request:

(a) Please provide the evidence upon which the statement on page 8-6 is based and the qualifications of the individual that undertook this analysis.

(b) Please explain why YECL is applying to increase its equity ratio to 44% when the generic benchmark ROE of 8.75% was established by the BCUC for a utility having a 38% equity ratio.

(c) Please indicate all cases in the last 5 years where YECL has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions. Please provide details.

(d) Is YECL planning to raise any capital to finance investment growth in the 2013-2015 test period?

(e) Please indicate whether YECL's ability to earn its allowed ROE will different at the current 40% common equity ratio as compared to proposed 44% common equity ratio.

(f) Please confirm YECL's understanding that reviews of capital structure and associated returns are typically only undertaken when there is a significant change in financial, business or corporate fundamentals. Please provide an exhaustive list of the significant changes in financial, business or corporate fundamentals that is driving YECL's proposed change in the equity component of rate base.

(g) Please provide all available Canadian comparables to YECL showing equity thickness, investment ratings, financial risk indicators and financial ratios (especially interest coverage).

(h) Please provide a table that reflects the actual annual ROE earned by YECL for 2009 through 2012.

(i) Please provide a table that reflects normalized actual annual ROE earned by YECL that is based on normalized volumes for 2009 through 2012.

(j) Please provide details of the change in revenue requirement for 2013, 2014 and 2015 by keeping the equity ratio at 40% and allowing a return on equity of 8.75%.

Response:

(a) Please refer to YUB-YECL-33(b) Attachment 1 for the Kathy McShane evidence from the 2008-2009 GRA. On page 22, Ms. McShane concludes Yukon Electrical:

i. Is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada

ii. Is of higher than average business risk within the spectrum of Canadian utilities and,

iii. Is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited.

An overview of Yukon Electrical's business risk as compared to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited, is as follows:

Market demand risk – both utilities are small in relative terms, serve similar northern based economies, have a concentration of sales in a relative small geographic area, must compete with alternative energy sources and have variations in sales due to weather.

Supply and physical (operating) risk – both utilities are supplied by crown owned utilities with Yukon Electrical, however, supplying approximately nine percent of its own supply requirements through Fish Lake hydro and its diesel plants. Both utilities' operations are subject to similar severe weather climates.

Regulatory risk – Yukon Electrical and Northland each are regulated by northern based public utilities boards, The Yukon Utilities Board and The NWT Public Utilities Board, respectively.

(b) Please refer to YUB-YECL-33(b) for the explanation as to why Yukon Electrical is applying for a common equity ratio to 44% as compared to the BCUC GCOC benchmark common equity ratio of 38.5%.

(c) Due to Yukon Electrical's subsidiary relationship with CU Inc., there have been no cases in the last 5 years where Yukon Electrical has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions.

(d) Yes.

(e) Under the stand alone principle, which encompasses the notion that the cost of capital incurred by Yukon Electrical should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters, Yukon Electrical would have difficulty accessing capital markets with a 40% common equity ratio which, in turn, would impact its ability to earn its allowed ROE.

(f) Not confirmed. Cost of capital reviews may be associated with a material change in market conditions or fundamental risks of the regulated entity, but may also occur periodically due to a pre-arranged schedule or the expiry of existing arrangements. Yukon Electrical's capital structure and ROE are being reviewed in this proceeding as part of its overall General Rate Application for 2013 – 2015. Yukon Electrical, in accordance with direction from the Board, has linked its capital structure and ROE to other jurisdictions to minimize costs and avoid expensive litigation of what are very complex matters. For the requested change in capital structure, please refer to part (b) above and Yukon Electrical's Application on page 8-6.

(g) For purposes of this Application and consistent with Yukon Board direction, Yukon Electrical's approach has been to efficiently link its ROE and common equity ratios to the BCUC GCOC as well to what has been approved by the Northwest Territories Public Utilities Board for the Northland companies, which share similar business risks with Yukon Electrical.

Further to the above, since 2008 the BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

In addition, as detailed in WL-YECL-17(b) Attachment 1, Yukon Electrical's forecast 2013 – 2015 financial credit metrics of FFO/Debt (20%) and FFO Interest Coverage (average of 4.36X) continue to fall within the ranges in Table 7 of the McShane evidence.

(h) The following ROEs for 2009-2012 are detailed on Schedule 8.1 of Yukon Electrical's Application:

2008: 7.03%

2009: 11.35%

2010: 10.54%

2011: 10.74%

2012: 10.18%

(i) Yukon Electrical's ROE based on normalized sales volumes for 2009 through 2012 would have been:

2009: 11.07%

2010: 11.37%

2011: 10.57%

2012: 9.41%

(j) Keeping the equity ratio at 40% and allowing a return on equity of 8.75% would reduce Yukon Electrical's revenue requirement by $440,000 (0.8%) for 2013, $542,000 (0.9%) for 2014 and $586,000 (1.0%) for 2015.

UCG-YECL-31

Reference: May 27, 2013 Application, page 8-6

Request:

(a) Please provide details of the long term debt YECL intends to issue during the 2013-2015 test period.

(b) Please provide details of the rates associated with any long, medium or short term debt issued by YECL over the last 10 years.

(c) Please compare the rates from part (b) with the Long Canada Bond Rates for that same period.

(d) Since YECL has proposed a deferral mechanism related to the return on equity, please provide your opinion on whether this same concept should apply to the issuance of debt which is largely not in the control of YECL.

Response:

(a) Please refer to UCG-YECL-31(a) Attachment 1.

(b) Please refer to UCG-YECL-31(b) Attachment 1.

(c) Please refer to UCG-YECL-31(b) Attachment 1.

(d) Yukon Electrical prepared its forecast of future rates using the best information available at the time of its application. Yukon Electrical has not applied for, nor does it favour, a change in approach with respect to the treatment of the cost of new debt.

The Yukon Electrical Company Limited
Long Term Debt Forecast to Be Issued 2013-2015

Series	Amount ($)	Coupon Rate	Effective Cost Rate *
Y	1,400,000	4.30%	4.35%
Z	13,700,000	5.00%	5.05%
AA	-	5.75%	5.80%

* The effective cost rate includes costs to issue debt.

Series	Issue Date	Yukon Electrical Rate	Long Canada Bond Rate
O	2004-01-23	5.47%	4.822%
P	2004-11-18	5.16%	4.546%
Q	2005-11-21	5.23%	4.293%
R	2006-11-20	5.07%	4.122%
S	2008-05-26	5.61%	4.083%
T	2008-05-26	5.62%	4.100%
U	2009-03-06	6.28%	3.565%
V	2009-03-06	6.55%	3.750%
W	2011-10-24	4.58%	2.943%
X	2012-11-14	3.89%	2.357%

* The Yukon Electrical Rate includes costs to issue debt.

UCG-YECL-32

Reference: May 27, 2013 Application, page 8-7

Request:

Please provide a copy of the table that appears at the top of page 8-7 with actual data from 2008 through 2012. Please provide all related source documents for the updated table.

Response:

The following tables summarize actual debenture issues by Yukon Electrical from 2008 through 2012:

	2008		2009	
Issue Date	May 26, 2008	May 26, 2008	Mar 6, 2009	Mar 6, 2009
Maturity Date	May 26, 2028	May 26, 2038	Mar 6, 2024	Mar 7, 2039
Long Canada Bond	4.083%	4.100%	3.565%	3.750%
Issue Spread	1.527%	1.520%	2.715%	2.800%
Debenture Rate	5.61%	5.62%	6.28%	6.55%

	2011	2012
Issue Date	Oct 24, 2011	Nov 14, 2012
Maturity Date	Oct 24, 2041	Nov 14, 2052
Long Canada Bond	2.943%	2.357%
Issue Spread	1.637%	1.533%
Debenture Rate	4.58%	3.89%

UCG-YECL-33

Reference: May 27, 2013 Application, page 8-7

YECL states that "*The no cost capital included in this Application relates to the balances for deferred pensions including other post employment benefit plans ("OPEB") as well as the reserve for injuries and damages.*"

Request:

(a) Please provide an explanation of the proposal being made by YECL regarding the section of the Application related to no cost capital.

(b) Please confirm whether YECL is earning any return on no cost capital and where this return is identified in the Application.

Response:

(a) Consistent with its last GRA and Board Order 2009-2, Yukon Electrical is proposing to continue to account for both pension and OPEB on the cash basis in the test period. The cash basis results in the charges equaling the forecast cash payments for each year.

For the reserve for injuries and damages, Yukon Electrical is proposing to amortize the balance of ($69,000) at the end of 2012 as well as the forecast annual charges for the test period over the three test years to bring the reserve balance to $0 as of December 31, 2015. The forecast annual charge of $100,000 for each test year is based on the average of the actual annual charges for 2010-2012.

(b) Yukon Electrical does not earn a return on no cost capital as detailed on Schedule 8.1 of its Application.

UCG-YECL-34

Reference: May 27, 2013 Application, page 8-10, Schedule 8.8

YECL states that it "*is using a deferral account to flow through to customers the costs associated with filing its GRAs. See Schedule 8.9 for a breakdown of the Phase I and Phase II costs forecast for 2013-2015. No rate case write-off is required from 2013-2015 to bring the overall deferred rate case balance to zero by the end of the test period*."

Request:

(a) Please confirm that the balance in the rate case costs deferral account was in a credit position (i.e., there had been an over-collection of costs) at the end of every year since 2008.

(b) Please confirm that YECL has already recovered the costs that it has forecast will be incurred in the current general rates application proceeding as well as the Phase II proceeding anticipated to be conducted in 2014.

(c) Please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs expected to be incurred by YECL in respect the current rates proceeding and a future rates proceeding prior to having them recovered in rates.

Response:

(a) Confirmed.

(b) Confirmed.

(c) Yukon Electrical only records approved costs into its rate case reserve. For purposes of the test period 2013–2015, Yukon Electrical has provided a forecast of what will be approved for regulatory costs through to the end of 2015. (Please refer to Schedule 8.8 line 23 and Schedule 8.9.) Actual approved costs for this period will be trued-up as part of Yukon Electrical's next GRA.

UCG-YECL-36

Reference: May 27, 2013 Application, page 8-10, Schedule 8.8

YECL states "*As part of its 2008-2009 GRA, Yukon Electrical forecast generation in the test period assuming the connection of Pelly Crossing to the main grid effective November 1, 2008. As the timing of commencement of the service was uncertain and the costs associated a change in the assumed connection date were material, Yukon Electrical received approval in Board Order 2009-2 for a deferral account for the incremental costs associated with any changes that resulted from reliance on the assumption. Pelly Crossing was connected to the grid on November 27, 2008, resulting in incremental costs of $33,000 which are included on Schedule 8.8. Yukon Electrical is proposing to collect $11,000 each year over the period 2013-2015 resulting in a zero balance of the end of the test period.*"

Request:

Given the YUB's rejection of YEC's proposed planning cost accounting policy in its Order 2013-01 (page 83), please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs incurred by YECL in respect to the deferred costs related to Pelly Crossing prior to having them recovered in rates.

Response:

In Board Order 2009-2, Yukon Electrical received approval for a deferral account for fuel costs associated with Pelly Crossing being connected to the grid before or after November 1, 2008. Pelly Crossing was connected to the grid on November 27, 2008, resulting in incremental fuel costs of $33,000. Please refer to UCG-YECL-36 Attachment 1 for a copy of the calculation.

The Yukon Electrical Company Limited
Calculation of Pelly Crossing Deferral

Forecast Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008 (per page 4-3 of the 2008-2009 GRA)		500	(a)
Actual Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		63,098	(b)
Incremental Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		62,598	(c) = (b) - (a)
Forecast Diesel Rate (per page 4-3 of the 2008-2009 GRA)	$	0.8933	(d)
Incremental Cost of Diesel Used at Pelly Crossing Subsequent to November 1, 2008	$	55,919	(e) = (c) * (d)
Prorate for Number of Days in Which Pelly Crossing Connection to the Grid Was Delayed	$	48,463	(f) = (e) x 26/30
Incremental Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		62,598	(c)
Forecast Heat Rate (per page 4-3 of the 2008-2009 GRA)		3.62	(g)
Incremental kwH Generated Using Diesel at Pelly Crossing		226,605	(h) = (c) * (f)
Forecast Purchased Power Rate (per page 4-3 of the 2008-2009 GRA)	$	0.0684	(i)
Incremental Savings on Purchased Power for Pelly Crossing Subsequent to November 1, 2008	$	15,500	(j)
Net Incremental Cost to Yukon Electrical Associated With Delay in Connection of Pelly Crossing to the Grid	$	32,963	(e) - (j)

UCG-YECL-38

Reference: May 27, 2013 Application, page 8-12

YECL states "*To determine the working capital for the 2013-2015 test period, Yukon Electrical completed a review of the components of each of the items in necessary working capital to ensure that the nature of the revenue/expenses included in each category had not changed materially since the 2008 lead/lag study was conducted and filed in Yukon Electrical's 2008-2009 GRA. Based on this review, the only component in the lead lag study that required an update was salary and wages lead/lag days as a result of Yukon Electrical moving to standard industry practice of bi-weekly payroll processing on January 1, 2010 with a one week payment lag.*"

Request:

Please provide all details of the lead/lag study review that verifies that only one component needed to be changed. Please provide all schedules in Excel format.

Response:

Based on Yukon Electrical management's knowledge of the operations, a review of each component was conducted and it was determined that there was no material changes in the types of revenues and expenses or in the payment terms, other than the change in the timing of payroll processing as discussed on page 8-12 of the Application. As a result, Yukon Electrical did not conduct a full lead/lag study for the purpose of this Application as it was determined to be unnecessary.

UCG-YECL-39

Reference: May 27, 2013 Application, Schedule 8.5

Request:

(a) Please confirm that YECL's actual rate base for 2008 and 2009 was lower in each year than was approved in the last general rates application review.

(b) Since rates for 2008 through 2012 were based in part on a return on rate base that was in excess of what would have been earned on actual rate base, please provide a calculation of the excess return incorporated in rates for 2008 through 2012.

Response:

(a) Confirmed. Yukon Electrical's rate base was $144,000 (0.3%) lower for 2008 and $362,000 (0.7%) lower for 2009 than was approved in its last GRA.

(b) Please refer to UCG-YECL-39(b) Attachment 1 for the calculation of return on rate base included in rates and the return on rate base that would have been earned on actual rate base for 2008 and 2009. Based solely on the differences between approved rate base and actual rate base, the higher than forecast return incorporated into rates was:

Year	Return on Rate Base Included in Rates ($000)	Return on Rate Base Based on Actual Rate Base ($000)	Excess Return Included in Rates ($000)
2008	3,519	3,508	11
2009	3,675	3,650	25

For each of 2010, 2011 and 2012, Yukon Electrical's actual rate base was higher than approved for 2009. As Yukon Electrical remained on 2009 rates for each of those years, there is a deficiency in the return on rate base that would have been earned on actual rate base as compared to the return on rate base included in rates.

The Yukon Electrical Company Limited
Return on Rate Base

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 GRA Approved				
Long-Term Debt	59.11%	27,244	6.87%	1,870
Common Stock	39.41%	18,162	9.08%	1,649
No Cost Capital	1.49%	685	0.00%	-
Total	100.00%	46,091	7.63%	3,519
2008 Based on Actual Rate Base				
Long-Term Debt	59.11%	27,158	6.87%	1,864
Common Stock	39.41%	18,105	9.08%	1,644
No Cost Capital	1.49%	683	0.00%	-
Total	100.00%	45,946	7.63%	3,508
2009 GRA Approved				
Long-Term Debt	59.17%	29,276	6.60%	1,934
Common Stock	39.45%	19,517	8.92%	1,741
No Cost Capital	1.38%	684	0.00%	-
Total	100.00%	49,478	7.43%	3,675
2009 Based on Actual Rate Base				
Long-Term Debt	59.17%	29,062	6.60%	1,920
Common Stock	39.45%	19,375	8.93%	1,730
No Cost Capital	1.38%	679	0.00%	-
Total	100.00%	49,116	7.43%	3,650

UCG-YECL-41

Reference: May 27, 2013 Application, page 9-4

YECL states "*A listing of the capital expenditures for 2008-2015 is provided in the following pages. For significant projects greater than $100,000, a description of the project is included. Business cases for all major capital projects ($500,000 or greater) are being filed with this Application as directed in Board Order 2009-2.*"

Board Order 2009-2, page 37

"*The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures.*"

Request:

(a) Please confirm that YECL considers "major capital projects" to only be those projects costing $500,000 or greater.

(b) Please provide references to YUB Orders in which Board defines what it believes to be the spending threshold for a major project for YECL.

(c) Does YECL believe that a utility with a $60 million rate base (such as YECL) should have the same expenditures threshold to define a major project as a utility with a $226 million rate base (such as YEC)?

Response:

(a) Confirmed.

(b) Yukon Electrical is not aware of any YUB Orders in which the Board defines what it believes to be the spending threshold for a major project for Yukon Electrical.

(c) Yukon Electrical believes it's reasonable to have a lower major project threshold than Yukon Energy. This is why it filed business cases for all capital projects $500,000 or greater as opposed to $1,000,000 or greater.

UCG-YECL-96

Reference: May 27, 2013 Application, Schedule 10.1

YECL is anticipating that its Utility Earnings Before Tax will increase by 45% in 2013 (over 2012), by another 32% in 2014 (over 2013) and by another 13% in 2015 (over 2014). By the time 2015 is ended, YECL is expecting its Utility earnings Before tax to increase by 117% over 2012 levels.

Request:

(a) Please provide a detailed explanation for why YECL's Utility Earnings Before Tax will increase at such an alarming rate between 2012 and 2015.

(b) Please provide a detailed explanation for the changes in YECL's CCA deduction between 2012 and 2015.

Response:

(a) Utility Earnings Before Tax is the sum of the Return on Common Stock, as calculated on Schedule 8.1 of the Application for each test year, and the Income Tax Provision, as calculated on Schedule 10.1 of the Application for each test year. As the Return on Common Stock is growing each year due to growth in rate base and the increase in the equity ratio from 40% to 44% for 2013-2015, the Utility Earnings Before Tax is also increasing between 2012 and 2015.

(b) The change in the CCA deduction is a function of: 1) undepreciated capital cost at the opening of the year plus the current year gross capital additions (subject to the half-year rule for the CCA claim); 2) reductions to gross capital adds, which include construction contributions and fully-deductible capitalized costs, as well as various other minor reductions; and 3) the mix of assets put into service as each asset CCA class has a different % rate.

As Yukon Electrical's capital additions are growing through the period 2012-2015, the CCA deduction is also increasing in that period.

UCG-YECL-97

Reference: May 27, 2013 Application, Section 11, Attachment 2

In response to YUB direction in its Decision 2009-2, YECL has provided details on the non-labour inflation rates used by 6 other utilities. Half of the utilities referenced by YECL are affiliates. YECL refers to this as a response to the YUB's request "to provide a study that compares what other utilities use as a basis for non-labour inflation rates".

May 27, 2013 Application, pages 1-6 – 1-7

YECL has assumed non-labour inflation rates of 1.9%, 2.0% and 2.1% for 2013, 2014 and 2015 respectively in its Application. For 2013, the proposed non-labour inflation rate is based on 50% of forecast Alberta inflation and 50% of forecast Yukon inflation. For 2014 and 2015, no forecast of Yukon inflation was available so the non-labour inflation rates applied by YECL are based on 50% of forecast Alberta inflation and 50% of forecast British Columbia inflation.

Request:

(a) Please explain why YECL's "study" did not include analysis included in a report released in October 2012 by the Ontario Energy Board (Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach) which notes that to the extent practicable, non-labour prices should be indexed by distribution industry-specific indices.

(b) What non-labour inflation rates are currently used by FortisBC Utilities, BC Hydro, Manitoba Hydro, NWT Power Corporation, SaskPower, ENMAX, Nova Scotia Power, New Brunswick Power and Qulliq Energy Corporation? Please provide reference material related to these rates.

(c) Please provide the sources of the non-inflation rates from Alberta, Yukon and British Columbia used by YECL to determine their proposed non-labour inflation rates.

(d) Given that YECL's "study" identified non-labour inflation rates used by utilities, please explain why YECL did not use one or more of these regulator-approved rates to determine its proposed non-labour inflation rates.

Response:

(a) In accordance with the Board direction, the purpose of the study was to provide information on what other utilities use as a basis for non-labour inflation rates. The study filed by Yukon Electrical on pages 11-15 and 11-16 of its Application shows that six utilities in Alberta and the Northwest Territories use CPI as a basis to forecast non-labour inflation rates, and that both the AUC and NWTPUB have approved the use of CPI to forecast inflation. While the results of the study are not exhaustive, the results show Yukon Electrical's pragmatic approach to forecasting inflation is consistent with approaches used and approved in neighbouring regulatory jurisdictions.

(b) Please refer to UCG-YECL-97(b) Attachment 1.

(c) Please refer to UCG-YECL-97(c) Attachment 1.

(d) Yukon Electrical based its non-labour inflation forecast on the best and most up-to-date information available at the time of filing. The regulator-approved rates quoted in the study were based on AUC and NWTPUB Decisions from 2011 and 2012, which was not the most current information available when Yukon Electrical filed its Application.

Utility	**Non-Labour Inflation Rate**	**Link**
Fortis BC Inc.	2013: 1.9%	Tab 4 Cost of Service, Page 43 of "FortisBC Inc. Application for Approval of 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan" Page 70 of "British Columbia Utilities Commission Order Number G-110-12"
BC Hydro	2013: 2.1% 2014: 2.1%	Page 5-11 of "British Columbia Hydro and Power Authority (BC Hydro) F2012 to F2014 Revenue Requirements Application"
Manitoba Hydro	Unknown	"Manitoba Hydro 2012/13 & 2013/14 General Rate Application" reviewed. This Application includes information about Canadian CPI for 2012/13 and 2013/14 and a comparison of the growth in Manitoba Hydro's growth in OM&A costs to CPI over the same period, but does not state what inflation rate is used by the utility in forecasting its non-labour costs.
NWT Power Corporation	2013/14: 2%	Page 76 of "Decision 1-2013 of The Public Utilities Board of the Northwest Territories"
SaskPower	2013: 2.0%	SaskPower's 2013 General Rate Application does not specify what non-labour inflation rate was used. However, page 20 of the "Forkast Consulting Independent Review of the SaskPower 2013 Rate Application" does state the inflation rate assumption.
ENMAX	Unknown	ENMAX is under Performance Based Regulation beginning in 2013. Therefore, ENMAX was not required to file a rate application for 2013 so no current inflation rate is available.
Nova Scotia Power	2013: 2.3%	Attachment 1, Pages 9 of 60 and 10 of 60 of the "NS Power 2013 General Rate Application"
New Brunswick Power	Unknown	Upon review of the NB Power and New Brunswick Energy & Utilities Board websites, no information regarding the current inflation rate used by NB Power could be located.
Qulliq Energy Corporation	Unknown	Upon review of the Qulliq Energy Corproation and Utility Rates Review Council of Nunavut websites, no information regarding the current inflation rate used by Qulliq could be located.

	2013 Forecast	2014 Forecast	2015 Forecast
Alberta CPI			
Bank of Montreal (Mar 1/13)	1.3	2.0	
CIBC World Markets (Jan 31/13)	1.1	2.4	
Conference Board of Canada (Feb 22, 2013)	1.8	2.2	
Global Insight (Feb 13/13)	1.9	2.1	2.2
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	2.4	2.4	
Alta Gov't Budget 2013 (Mar 8, 2013)	1.8	1.8	1.8
Average	**1.7**	**2.1**	**2.0**
Yukon CPI			
Yukon Gov't (Yukon Econ Development, Feb 5, 2013)	**2.0**		
British Columbia CPI			
Bank of Montreal (Mar 1/13)	1.1		
CIBC World Markets (Jan 31/13)	1.7		
Conference Board of Canada (Feb 22, 2013)	0.6	1.9	2.2
Global Insight (Feb 13/13)	1.0	1.9	2.0
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	0.6	1.9	2.2
BC Gov't Budget 2012 (Feb 19, 2013)	1.5	2	2.1
Average	**1.1**	**1.9**	**2.1**
Yukon Electrical Other Inflation Forecast	**1.9**	**2.0**	**2.1**

UCG-YECL-98

Reference: May 27, 2013 Application, Section 11, Attachment 6

In response to YUB directive, YECL states that it has participated in a joint government and utilities working group, led by the Government of Yukon, which was established to develop an IPP policy.

Request:

(a) Please provide details on how and when the referenced working group was established in light of the YUB's direction in February 2009.

(b) Please provide details on how often the working group has met since its formation and how often information / positions / comments have been exchanged.

(c) Please provide a copy of all materials and positions authored by YECL that have been contributed to this consultation process.

Response:

(a) The Yukon Territorial Government began background work on the development of an Independent Power Production Policy in late 2008 and formed a working group with Yukon Electrical and Yukon Energy to begin drafting a policy in the first quarter of 2009.

The structure of this group includes a Steering Committee made up of senior membership from both utilities. The Yukon Government gives direction to the working group, which is also made up of members from all three parties. This policy initiative is being led by the Yukon Government.

(b) As requested by the Yukon Government, Yukon Electrical has met as part of this working group. During the key drafting stages of the IPP Policy, this group has met as often as every two weeks. The policy is currently being reviewed internally by the Yukon Government in advance of it being released for public consultation.

(c) Yukon Electrical has not authored formal positions to the process, but rather, has contributed expertise and information as requested by the Yukon Government. As such, Yukon Electrical has no authored positions to provide.

UCG-YECL-128

Reference: May 27, 2013 Application, Business Case #30 - DSM

Based on full implementation of the five year DSM plan, the Utilities commit to an electricity conservation target of 8.5 GWh of sustained savings by year five.

Request:

(a) The utilities state (page 3) that the proposed DSM Plan "was developed by the utilities in collaboration with interveners, Yukon NGOs, community leaders, First Nation governments and the general public". Please provide details of presentations made and discussions held by the utilities regarding the proposed DSM plan with the each of these stakeholder groups prior to submitting it to the YUB on May 27, 2013. Please include details of how many individuals from these stakeholder groups were involved in each consultation.

(b) Why did the utilities not consult with builders, building contractors and trades specialists?

(c) Please provide details of any discussions, surveys, etc. that the utilities conducted of customer groups to determine if it should offer DSM programming.

(d) Please provide a table that lists all customer classes who have participated in the DSM programs either offered or supported by the utilities from 2008-2012. In the table include the number of programs each customer has participated in, the year(s) they were a participant, if the program was a standard resource acquisition program or a large industrial/commercial specific program, the amount of incentive dollars received by each participant (divided by year), and the cumulative electricity savings achieved each year. (redact the names of the customers if necessary)

(e) Please advise how much less electricity in kWh was being consumed in the Yukon in 2012 as a result of the DSM programs delivered by the utilities since 2008. Please provide specific details on the measurement of this amount.

(f) How much of the proposed DSM plan is targeted at ratepayers living on low and/or fixed incomes? Please compare this to the proportion of DSM programs in other jurisdictions that are dedicated to low income ratepayers.

(g) Please provide a table that lists of all the programs the utilities considered for inclusion in its DSM Plan, the TRC ratio for each program, the cost for each program and the rationale for or against proceeding with the program.

(h) Please confirm that for savings to be eligible to be counted towards the DSM savings targets, the savings must be verified using industry-based evaluation, measurement and verification protocols. Please provide the EM&V protocols that the utilities will be using.

(i) How will the annual results of the proposed DSM program be audited and by whom?

(j) How will the savings generated by utility-sponsored DSM programs be isolated from savings resulting from Yukon government-sponsored DSM and energy conservation programs?

(k) Please set out all steps that the utilities will take over the term of the proposed DSM plan to ensure that all parties have confidence in the electricity savings delivered within the DSM portfolio.

(l) In this and other programs that are based on the level of efficiency in the Yukon's Building Standards Act and the National Building Code, there is a fundamental expectation that all builders fully comply with the legislation and that the performance of the homes and buildings once built and in operation actually achieve the levels anticipated by the legislation. Have the utilities done any research to determine if such assumptions are valid? Are the utilities aware of any research by any other organization or agency to validate the performance of homes and buildings relative to legislated assumptions? If it is the case that homes and buildings are not performing as expected under the Code, would not the utilities' estimates of the impact of its DSM programs to go beyond Code actually understate the savings achieved?

(m) Are the utilities seeking approval of all the elements of the proposed DSM Plan for five years? To the extent that the utilities wish to make changes to the proposed DSM Plan during this five-year period, what process is proposed in order to obtain Board approval for those changes?

(n) Please explain how the utilities will allocate the costs of the proposed DSM Plan between the various rate classes. Does the allocation of these costs take into

account differences between the participation levels and savings per participant between the various customer classes?

(o) Please provide a table (or tables) showing for 2008, 2009, 2010, 2011, 2012, 2013, 2014 and 2015 how the DSM costs are allocated to each rate class. In showing the DSM costs allocated to each rate class, please indicate the average rate impact for each rate class.

(p) Please identify all advantages associated with approval of a 5-year DSM framework rather than a 1-year DSM framework.

(q) Please identify the advantages associated with approval of a 1-year DSM framework rather than a 5-year DSM framework.

(r) Have the utilities identified any cost efficiencies with proceeding with a 5-year DSM framework rather than a 1-year DSM framework? If so, please identify all those cost efficiencies. Further, if cost efficiencies have been identified, please explain how those cost efficiencies are passed on to ratepayers.

(s) Do the utilities agree that large industrial customers have the expertise to undertake energy efficiency programs on their own so ratepayer funded DSM programs for large industrial customers should not be mandatory?

(t) What penalties will be incurred by the utilities if they do not meet the electricity conservation target of 8.5 GWh of sustained savings by year five?

(u) In order to adequately challenge the utilities to drive increased participation to target levels, have the utilities considered the use of a variance account such that the utilities will only be reimbursed up to a maximum amount based on achievement of targeted savings levels?

(v) What market barriers have the utilities identified to providing DSM to privately-owned multi-unit residential buildings?

(w) Have the utilities studied other jurisdictions that are providing DSM programs to privately-owned multi-unit residential buildings? If yes, please provide the related research.

(x) Have the utilities analyzed the potential impacts of system level efficiency savings on the price ratepayers pay for electricity? If so, please provide the analysis.

(y) What is the target reduction in peak electricity demand over the 5 year plan period?

(z) What is the required take-up of each proposed DSM program in order to ensure that the savings target will be achieved?

(aa) Please provide any market potential studies / working papers that relate to the housing stock targeted by the proposed DSM plan for social housing units.

Response:

(a) Consultation and workshops with stakeholders began in January 2011 and continued through to June 2013 when the final program design was rolled out to the public. The materials presented along with attendance information, where available, is attached in the following documents:

- *Alexco Presentation Apr2012* (UCG-YECL-128(a) Attachment 1)
- *AYC Presentation Nov2012* (UCG-YECL-128(a) Attachment 2)
- *CPR Kickoff May2011* (UCG-YECL-128(a) Attachment 3)
- *CPR Study visit May2011* (UCG-YECL-128(a) Attachment 4)
- *DSM Working Group Presentation Apr2012* (UCG-YECL-128(a) Attachment 5)
- *DSM Workshop Report Apr2012* (UCG-YECL-128(a) Attachment 6)
- *DSM Workshop Apr2012* (UCG-YECL-128(a) Attachment 7)
- *DSM for the Yukon June2013* (UCG-YECL-128(a) Attachment 8)
- *Focus Group Workshop Jan2011* (UCG-YECL-128(a) Attachment 9)
- *John Streicker Presentation Apr2012* (UCG-YECL-128(a) Attachment 10)
- *One Change Consultation June2011* (UCG-YECL-128(a) Attachment 11)
- *UCG Presentation Apr2012* (UCG-YECL-128(a) Attachment 12)
- *YCS Presentation Apr2012* (UCG-YECL-128(a) Attachment 13)
- *YEC Charette March2011* (UCG-YECL-128(a) Attachment 14)
- *Workshop Attendance Nov2011* (UCG-YECL-128(a) Attachment 15)
- *CPR Workshop May2011* (UCG-YECL-128(a) Attachment 16)

(b) The utilities consulted with builders, building contractors and trade specialists through the market characterization process. Please refer to the *DSM Market Characterization Methodology*, provided as UCG-YECL-128(b) Attachment 1, for details.

(c) Please refer to the attached documents of details of surveys conducted with customers.

- *One Change Survey June 2011* (UCG-YECL-128(c) Attachment 1)
- *YEC Knowledge Awareness Opinion Survey* (UCG-YECL-128(c) Attachment 2)
- *YEC Public and Stakeholder Survey July 2011* (UCG-YECL-128(c) Attachment 3)
- *YEC Public and Stakeholder Survey June 2010* (UCG-YECL-128(c) Attachment 4)

(d) There were no programs under the joint DSM plan delivered from 2008-2012, so no customer participation information can be provided.

(e) There were no programs under the joint DSM plan delivered from 2008-2012, so there was no reduction in electricity consumption as a result of DSM for the period.

(f) The utilities have no visibility of ratepayer income levels.

(g) The DSM programs were developed based on a set of considered technologies for application in programs. A Total Resource Cost Test (TRC) was not performed on programs, but on individual measures as part of the four cost effectiveness tests. The TRC on the selected measures are detailed in *DSM Program Incentive Justification Levels*, provided as YUB-YECL-27 Attachment 1.

The first task in the planning process was to determine which of the several hundred technologies and measures analyzed in the Yukon CPR 2011 were appropriate for the Yukon context *(*details can be found in *Appendices G1-G4* of the *Yukon Five Year Demand Side Management Plan* filed with the Application*)*. As a starting point in the extensive listing of individual measures and technologies contained in the Conservation Potential Review, results were screened using a 7 step process as outlined below (taken from Exhibit 2, page 3, Appendix E of the *Yukon Five Year Demand Side Management Plan* filed with the Application):

Exhibit 2: Priority Opportunities Screening Process

Step 1: The Economic Potential and Achievable Potential results for the residential and commercial sectors were sorted on the basis of the following criteria:

- Measures providing the largest electricity savings potential by Y3 and by 2020
- Measures providing electricity savings at the lowest levelized cost
- Measures providing electricity savings with the shortest customer payback

Step 2: Based on the results of Step 1, individual measures were assigned priority, with highest priority assigned to those measures that provided the largest savings potential in the period at the lowest levelized cost of electricity under the total resource cost test (see 1.3.3 below).

Step 3: Priority measures from Step 2 were grouped into "opportunity areas" e.g., multiple individual commercial lighting measures were combined into a single aggregate "commercial lighting" opportunity. As applicable, complementary measures with smaller savings potential and/or higher levelized costs of electricity were added to the applicable opportunity area. The composition of the package of measures contained in the selected opportunity areas also considered factors such as: commonality of market delivery channels, information flows, typical purchase decision making processes etc.

Step 4: The qualitative notes from the CPR achievable potential workshops were reviewed to determine if participants had noted any compelling technology or market considerations, either positive or negative, that would potentially affect the priorities established in Step 3. Customer payback periods, as generated in Step 1, were also considered at this time. The assigned priority for each "opportunity area" was adjusted, as applicable.

Step 5: A brief scan of DSM program experience in other jurisdictions was conducted with the objective of identifying potential program delivery experience that would affect the priorities established in Step 3. The assigned priority for each "opportunity area" was adjusted, as applicable.

Step 6: The estimated upper and lower achievable potential electricity savings for the resulting combined residential and commercial sector opportunity areas was calculated, together with an approximate weighted average CCE for each opportunity area. The results were compared with the notional 5 GWh/year savings target.

Step 7: A select number of opportunity areas were recommended for this initial set of DSM programs.

(h) Confirmed. The utilities' Evaluation, Measurement and Verification Plan will follow the general principles of the California Evaluation Framework and the California Evaluation Protocols as these are the standard reference books utilized across North America. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details of the protocols that will be utilized.

(i) The utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities. Third-party evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. The utilities intend to follow the general principles of the California Evaluation Framework and the California Evaluation Protocols as these are the standard reference books utilized across North-America. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details of how annual results will be calculated and verified.

(j) The electricity saving achieved by the five-year DSM plan will be evaluated and verified by the process set-out in the EM&V plan. This plan uses a deemed savings approach and is specific to the measures outlined in the Program Portfolio. Government sponsored programs will not be part of the reporting of the five-year DSM plan. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for further details of how the utilities will report savings.

(k) The utilities' DSM staff will track a set of indicators to justify results, suggest corrective measures, and update targets for the next period. Additionally, the utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities. Third-party program evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. Please refer to section 3, pages 13-24 of the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for an overview of EM&V for the proposed DSM program portfolio. Additional EM&V process details by program can be found in the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

(l) The utilities have not done any research to determine if the assumptions regarding builder compliance with legislation and performance of buildings once built are valid.

The utilities are not aware of any specific research related to validating the performance of homes and buildings. Compliance with the code is the generally-accepted baseline scenario among utilities and DSM program administrators.

The utilities expect on average that buildings will perform to the National Building Code and the Yukon's Building Standards Acts as it applies to to the modeling completed as part of the DSM study. The utilities' approach to estimate the impact will match in rigor that of other North American utilities. Buildings that exceed building code standards or do not meet them would have varying results.

(m) Yes, the utilities are seeking approval for the five year plan. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details related to Board communication regarding changes in the programs.

(n) This question will be examined as part of a future Phase II process.

(o) This question will be examined as part of a future Phase II process.

(p) The advantages associated with approval of a five-year DSM framework are:

- Drafting a new DSM portfolio application every year would require a considerable investment in time and materials; either requiring the involvement of external consultants or pulling the program management staff out of their regular operations. This would then impact customer satisfaction and program performance.

- Stability of the program portfolio / Lower risk of abrupt changes in policy, or programs being cancelled without proper exit strategy.

    - Both end-users and trade allies want to be able to trust in the availability of the programs when planning capital investment. This, stability will increase both customer satisfaction and program uptake.

    - The utilities can carefully plan communications around anticipated program changes and evolutions, as applicable.

- Greater job stability for DSM staff. Stable, seasoned and talented DSM staff will result in greater customer satisfaction, and higher impact.

- Greater flexibility provided to the utilities to react to changing market conditions, early results and feedback from customers and trade allies.

    - Performance will still be reported to the regulator on an annual basis as well as anticipated changes, they will be commented on, and the utilities will account for the comments when implementing the changes.

- Best value third-party evaluation, measurement and verification:

    - More methodological options are available to evaluators when working with more participation data and more transactions. For example: sampling, billing analysis.

    - Program-induced transformations in the markets are challenging to observe in a timeframe that is less than 5 years.

    - One-year worth of evaluation budget in the Yukon is inadequate. It is not enough “critical mass” to cover the base cost of doing business with a seasoned EM&V contractor and would reflect badly on the quality of the evaluation work.

- 5 years is sufficient time to take the program portfolio to market, and then register results and market feedback in sufficient volume.

    - Launching a portfolio from scratch requires building a transactional infrastructure, communication materials, reassign/hire and train staff, and get the word out about the program. It takes a few months before the first residential transaction is actually recorded, and then only a few months later will the portfolio be in full swing – beyond the 1-year time window.

    - Moreover, the program portfolio has commercial/institutional DSM initiatives in the mix. Transactions in this sector are slower to develop because investments in the commercial/institutional sector are generally planned by the prospective participants one year ahead or more. The first general-service transactions might only be registered on the second year of operation.

- Because of the above, assessing the program after one or even two years of operation would be premature.

(q) A one-year plan would allow for a higher level of scrutiny of the programs. For the reasons listed in question UCG-YECL-128(p), the utilities did not feel that a one-year plan was cost-effective, nor that a one-year time frame would allow for proper evaluation, measurement and verification or a high level of customer service.

(r) Yes. The utilities have identified cost efficiencies with proceeding with a 5-year DSM framework rather than a 1-year framework.

- Drafting a new DSM portfolio application every year will require a considerable investment in time and materials, either requiring the involvement of external consultants or pulling the program management staff out of their regular operations, which would then impact customer satisfaction and program performance.

- The standard practice is to have the Conservation Potential Review (CPR) updated for a jurisdiction, in this case the Yukon, every 5th year. There is value in using the CPR result to re-shape the portfolio for the next DSM operation window.

- The EM&V budget will hardly reach a critical mass in one year, which would therefore make it not worthwhile.

- The size of the Yukon jurisdiction makes it challenging to plan and deliver a cost-effective DSM portfolio in one year versus five years.

(s) The utilities have no visibility of the expertise of their industrial customers.

(t) No penalties will be incurred.

(u) No, the utilities have not considered this approach.

(v) In the Market Characterization Research it was concluded that:

> …many apartment blocks in the Yukon were built in the 70's and they were paid for a long time ago. The owners do not need electricity efficiency to remain price competitive, the good energy rebate [offered by ESC] for instance seemed insufficient to tackle

this barrier. (Section 4.1, page 66, Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application)

(w) No, the utilities did not examine other jurisdictions related to privately-owned multi-unit residential buildings.

(x) System-wide efficiency savings are not part of the joint DSM plan.

(y) All programs included in the DSM Plan have coincidental peak savings, as outlined for each program shown in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management* Plan included in the Application. There are no specific programs to address peak shifting included in the DSM plan. Peak shifting programs tend to be costly and complex to administer as they require a high degree of customer participation and generally require enforceable regulation to ensure the technology is used during those peak times. Under the current rate structure and customer available data, there is no customer incentive to develop programing to address peak shifting. In developing their first DSM programs, the utilities focused on electricity usage savings which is more cost effective and results in coincidental peak savings.

(z) Each program within the five-year DSM plan has annual participation rates identified. The participant take-up rate for each program is detailed in UCG-YECL-128(z) Attachment 1.

(aa) There are no specific targeted programs for social housing units and no studies were undertaken.

ALEXCO

Demand Side Management
&
Audit Review

April 2012

ALEXCO

Keno Hill Project Overview



KEY Reasons for Involvement

2011 Demand Side Management Energy Audit

- Mutually beneficial partnership between YEC & Alexco

- Identified areas which allow Alexco to:
  - ✓ Reduce peak usage
  - ✓ Reduce total energy usage
  - ✓ Identify possible efficiencies
  - ✓ Further reduce energy footprint



ALEXCO

Demand Side Energy Consultants

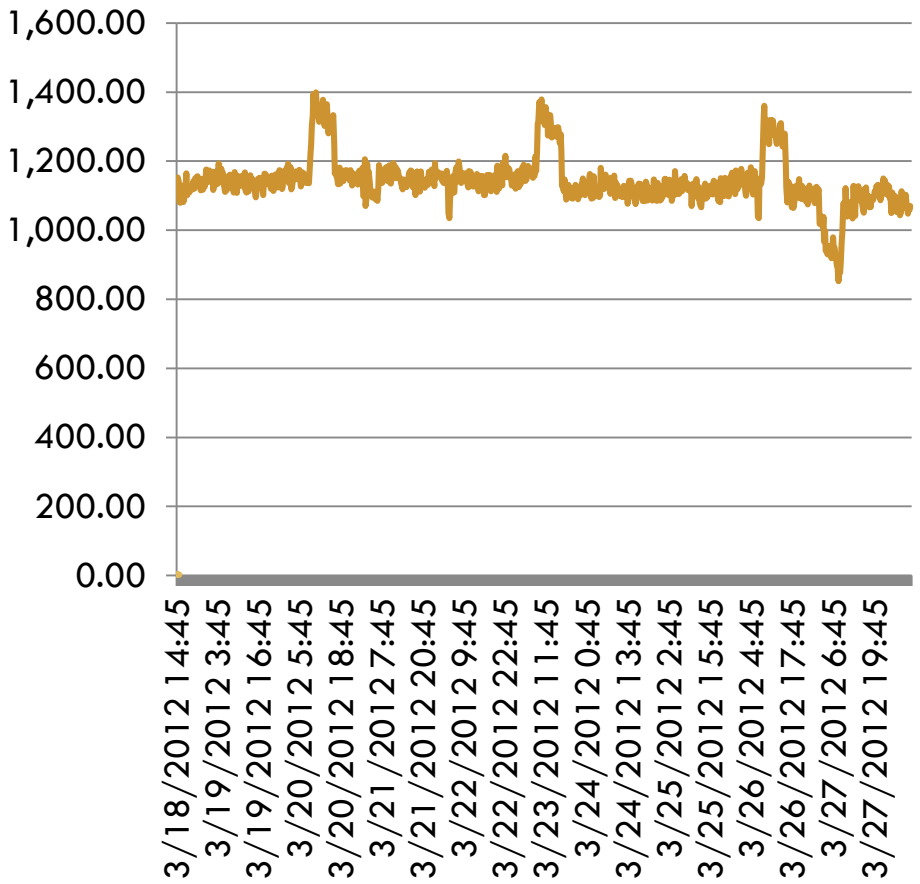
Study Scope

1.	2.	3.	4.
Observation of Keno Hill Project operational procedures	**Comparison of other projects to Keno Hill Project**	**Analysis of utilization rates & operational parameters**	**Final report & recommendations to Alexco & YEC**
1 week at site Off-site consulting work	Database comparison for efficiency gains	Large equipment such as: air compressors, crushers, blower, ball mill …	Operational recommendations & capital projects

ALEXCO

Typical Energy Profile

- Base Load = Daily Steady State Operations
- All infrastructure must be sized to peak load
- Peaks are associated with ore crushing operations



ALEXCO

Recommendations of Demand Side Audit

1. Instillation of an ammeter in Mill operators cab
2. Convert plant lighting to T5 HO fluorescents & LED's for outdoors
3. Re-commission mill air system
4. Initiate compressed air leak reduction program
5. Commission the air blower inlet modulation
6. Re-apply variable frequency drives to Mine ventilation
7. Optimize plant process thru program logic controller
8. Install electrical sub-metering for Mine
9. kWh per tonne as performance measure
10. Install capacitors on the 600V Mill

ALEXCO

Status of Recommendations

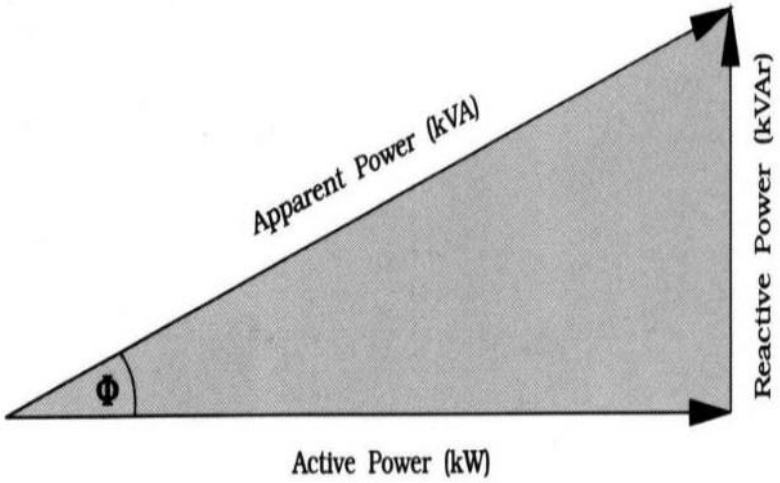
- ✓ Investigation of alternate lighting options (LED's) - in progress
- ✓ Mill compressed air system has been re-commissioned
- ✓ Ongoing air leak reduction program at Mill & Mine
- ✓ Additional variable frequency drives have been installed
- ✓ Program logic control on filter presses implemented
- ✓ Evaluation of site power distribution & metering options - in progress
- ✓ Cost benefit analysis & design of power factor correction unit for the Mill – in progress

ALEXCO

Power Factor (PF)

- Power Factor is a measure of how effectively the power is being used and is a ratio of "active power" used to the "apparent power" required which is a combination of both active power & reactive power

- 0.85 for normal operations
- 0.75 for peak loading conditions
  - For every unit of power required to run upwards of 15-20% more power needs to be provided
- 0.95 – 0.98 PF with correction



- **PF = Active Power / Apparent Power**

ALEXCO

Future Considerations

- Increased use of variable frequency drives on motors
- Power factor correction studies
- Energy measuring devices
- Alternative lighting sources
- Proper equipment sizing & selection
- Ongoing evaluation of operational practices

Alexco Contact Info

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Keno Hill Silver District
Elsa, Yukon Y0B 1G0
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F: 867-995-2600

The Value of Electricity Conservation

A presentation for AYC from Yukon Energy Corporation and Yukon Electrical Company Limited

1. **What** is electricity conservation?
2. **Why** should we conserve?
3. **How much** are we using?
4. **Where** can we start?
5. What comes next?

What is electricity conservation?

1. People making the best use of the electricity that is available

2. Increased efficiency of buildings, products, and processes

Why should we conserve?

Implementing new technologies could considerably reduce your annual operating budget

Implementing new ways of doing the same old thing could save your employees time AND save money on your electricity bill

Electricity savings = $ savings

Why should we conserve?



Environmental stewardship is important to many communities and their citizens

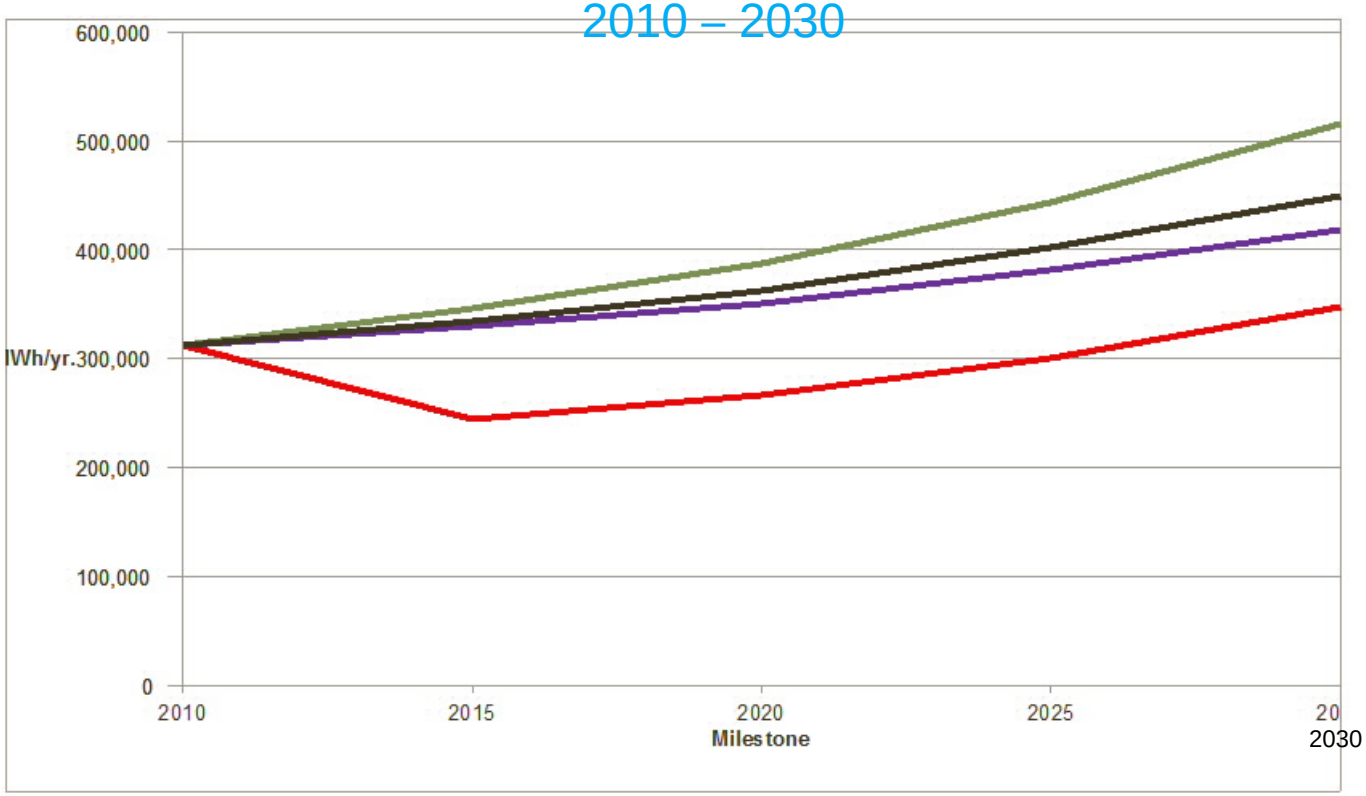
ICSPs/OTOF

The Yukon's supply of renewable resources is **limited**; Conservation is a renewable resource that **all Yukoners** can participate in providing

Electricity savings = responsible resource management

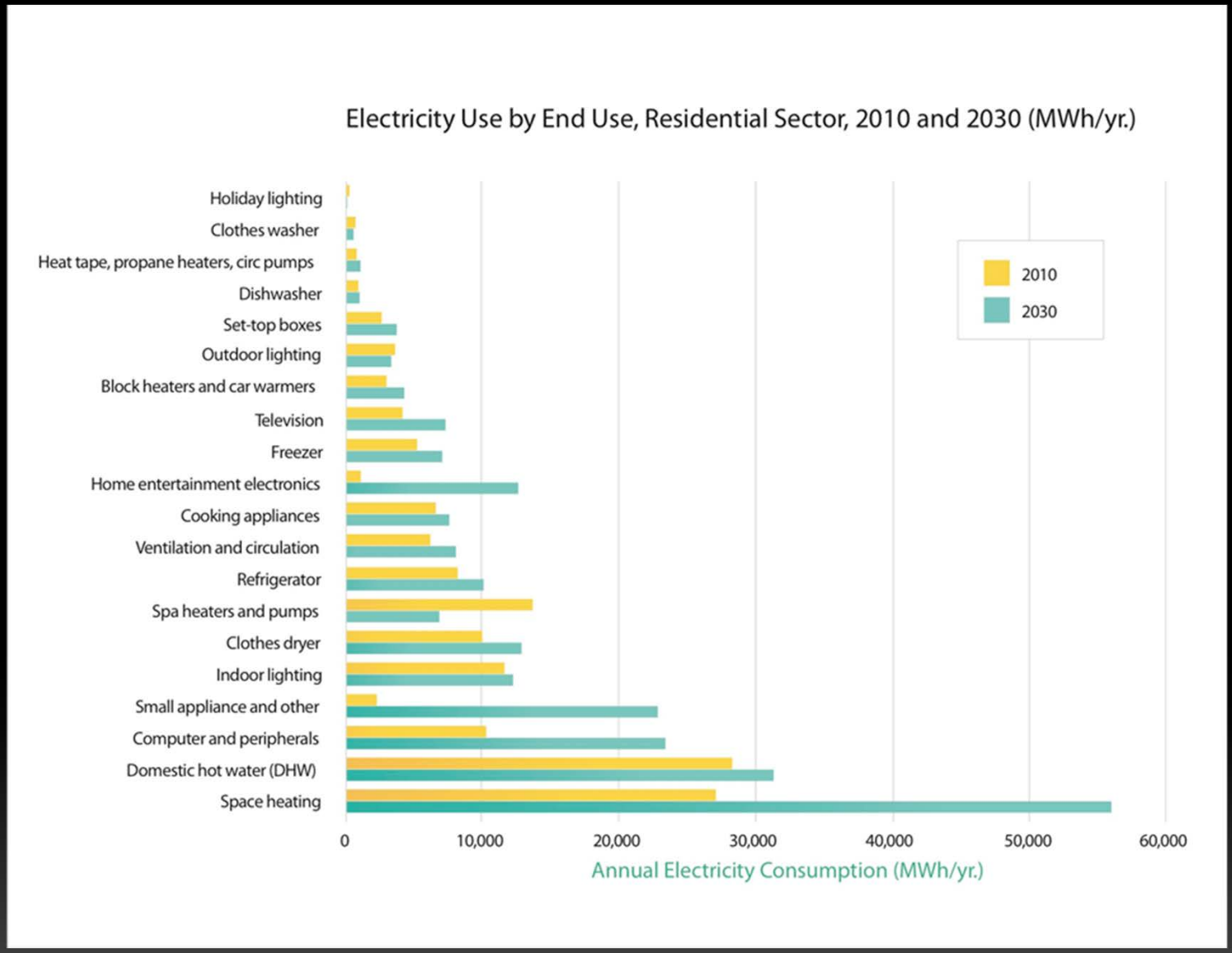
WHY SHOULD WE CONSERVE?

Growth in Residential and General Service electricity usage in Yukon (MWh/yr) 2010 – 2030



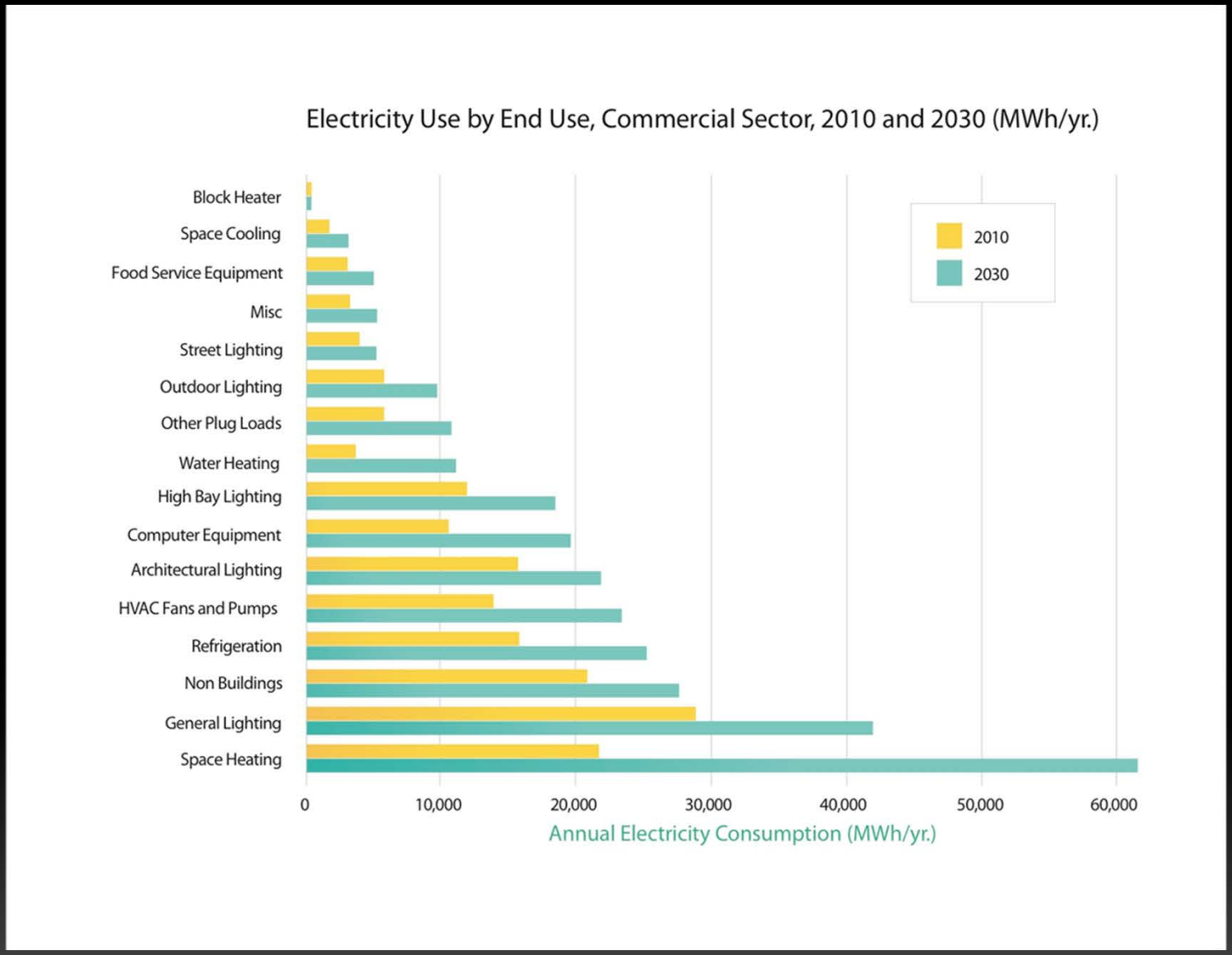
Green represents anticipated growth of electricity necessary to supply the Residential and General Service rate classes 2010-2030. Black and purple lines represent the achievable potential of conservation to impact growth.

HOW MUCH ARE WE USING?



The graph above describes the ways we use electricity in the residential sector, how much each of those uses contributes to electricity consumption and how we expect that to grow between 2010 and 2030. All numbers are based on real Yukon data.

HOW MUCH ARE WE USING?



The graph above describes the ways we use electricity in the general service sector, how much each of those uses contributes to electricity consumption and how we expect that to grow between 2010 and 2030. All numbers are based on real Yukon data.

How much are we using?

- Dollars to Sense courses
  - http://oee.nrcan.gc.ca/industrial/training-awareness/2442
- Energy Benchmarking tools
  - http://oee.nrcan.gc.ca/industrial/technical-info/benchmarking/4377#energy-performance
- Energy audits
- Reading your bill
  - http://www.yukonenergy.ca/customer/tips_tools/reading/
  - YECL link

Knowledge is Power

Understanding how your buildings and processes are using electricity can help you make informed choices about electricity conservation projects

Completing a desktop **audit** or an in-depth audit can give you valuable information about payback and can help you choose the best projects to meet your objectives

Recognize the $ value

Capital – Operational – HR

- Making the most efficient choice sometimes costs more capital but it can reduce both operational and HR costs
- Factor in lifetime costs and savings
- Behavioral change has no capital cost and can greatly enhance operational/HR savings

Recognize value beyond $

Responsibility – Security – Progress

- Electricity demand is growing
- Cost of electricity is gradually increasing
- Energy efficient materials and equipment sometimes have added benefits (longer life, health and safety, etc.)

Next Steps

What you need

- Understanding of **how electricity is used**
- Understanding of equipment and **processes** currently in place
- Information about energy efficient alternatives
- Lifecycle comparison

Who can help?

- YECL and YEC staff and websites can help you understand your bill; YECL can help you access data
- Operations and Maintenance **personnel**
- YECs Energy Conservation Dept., YECL, ESC, NRCan, Dollars to Sense

Where to begin?



Yukon Electrical can assist

- Provide historical consumption records
- Consolidate all accounts to a single monthly statement
- Provide a monthly electronic statement
- Provide rate calculation sheet to estimate savings potential

What makes up the charges on my Yukon Electrical bill?

- Demand
- Energy
- Riders and Taxes

How is energy charged?

General Service Rate Blocks

- 1 – 2000 kW.h = 10.00 ¢/KW.h
- 2001 – 15,000 kW.h =12.88 ¢/KW.h
- 15,001 – 20,000 kW.h = 15.68 ¢/KW.h
- 20,001 and over = varies by generation type

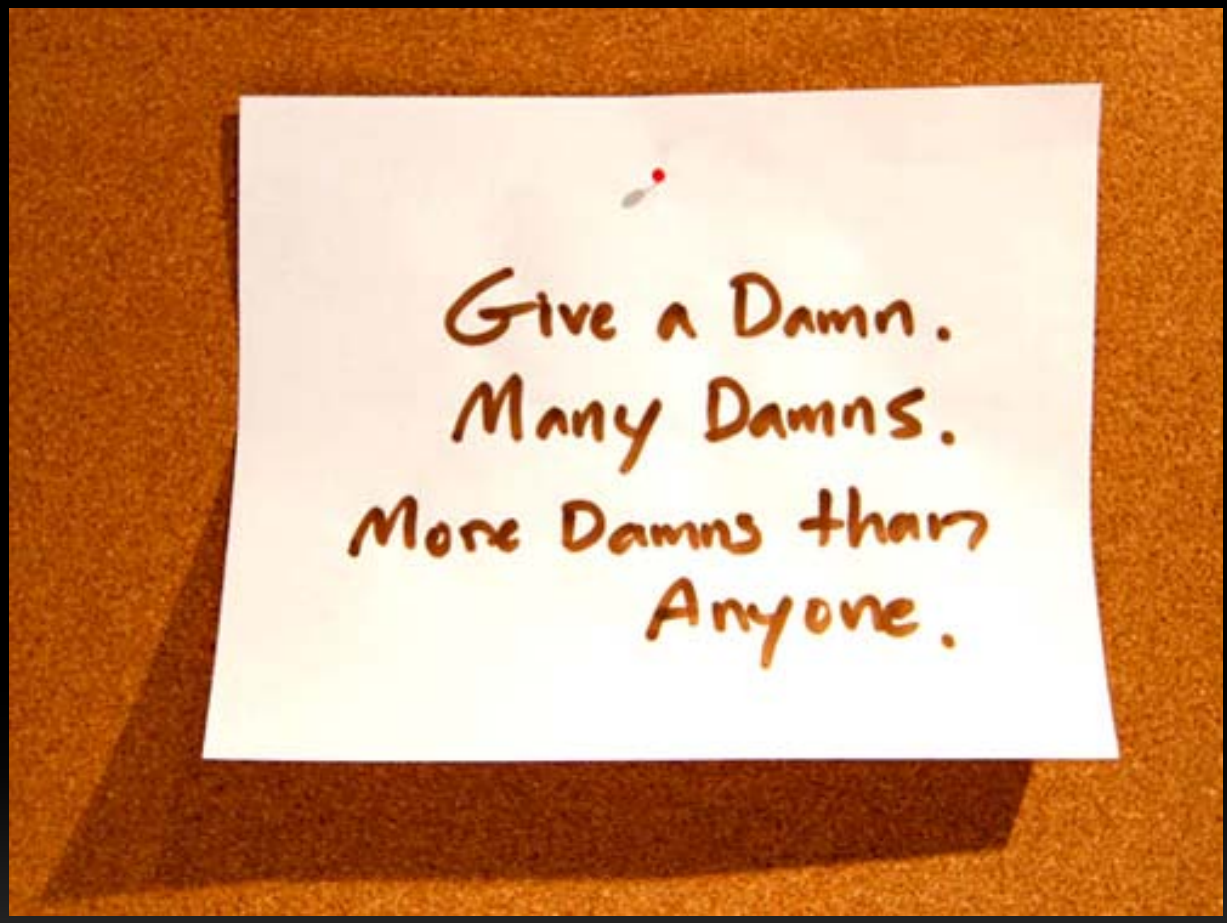
Understanding demand charges

- Measured demand is the result of the maximum draw required to meet coincidental use of equipment.
- The demand marker moves to record the maximum draw and is reset to zero each month at meter reading time.
- The monthly demand charge can be influenced by the previous 12 months.
- A peak demand can be set between the months of October and March.

How to reduce demand charges?

- Rethink the way equipment is started and used
- When replacing equipment consider
  - Operating costs
  - Capital Cost

THANK YOU



Jessica Thiessen (Yukon Energy) 208-212 Main St. Whitehorse 867-393-3898
http://www.yukonenergy.ca/energy/projects/dsm/

Wendy Scramstad (Yukon Electrical Company Ltd.) Whitehorse 867-633-7027



Yukon Conservation Potential Review (CPR)

Start up Meeting
May 2, 2011

Yukon CPR

Agenda

ICF Marbek

- Introductions
- Overview of Yukon Electricity Context
- Overview of CPR Work Plan
- Detailed Discussions of CPR Task Areas
- Wrap up & Lunch

Yukon CPR

Introductions

ICF Marbek

- Name
- Organization
- Primary Area(s) of Interest

Yukon CPR

Workshop Objectives

- Develop shared client/consultant understanding of:
  - Yukon DSM/CDM vision & challenges
  - Proposed CPR task areas, including deliverables and priorities
  - Client/consultant roles and responsibilities
- Ideas that can improve the proposed study approach



Yukon Electricity Context

- CDM Goals and Drivers
- Challenges
- CPR Expectations

Yukon CPR



Overview of Study Approach

- CPRs – lessons learned
- Our Team
- Study Work Plan & Results
- Schedule
- Working Together

Yukon CPR

CPRs – Lessons Learned

- Experience in other jurisdictions
  - ~ 15 CPRs completed in Canada in past decade
  - Virtually all Canadian electricity and natural gas companies
- Conclusion
  - ~ 50% Organization Development
  - ~ 50% Analytic and Modelling
  - By study's conclusion – all participants should have a shared vision of:
    - The size of the CDM/DSM potential
    - The most significant opportunities
    - The challenges and the preferred approaches for realizing the potential

Yukon CPR

About ICF Marbek

Marbek (1983 – 2011)

- Private Canadian company
- Energy and environment services to government, utilities, private sector, industry associations and research agencies in Canada and internationally
- Energy Practice (Energy Efficiency and Renewable Energy) – 4 business areas:
  - Energy System Planning (e.g., CPRs)
  - Energy Policy & Programs (design, implementation and evaluation)
  - Commercial Energy Services (e.g., facility energy audits, energy management plans, portfolio energy benchmarking etc.)
  - Industrial Energy Services (e.g., facility energy audits, energy management plans, portfolio energy benchmarking etc.)

Yukon CPR

About ICF Marbek

ICF Marbek

- January 1, 2011 – joined with ICF International
- Together, creates Canada's leading fully integrated energy, climate, and environmental consultancy specializing in energy efficiency and renewable energy
- Provides large pool of expertise to draw upon e.g.
  - ICF manages the design and implementation of U.S. Energy Star program on behalf of U.S. EPA
  - Design and implementation of large DSM programs on behalf of U.S. government and utility clients, many have been nationally acclaimed

Yukon CPR

Study Team

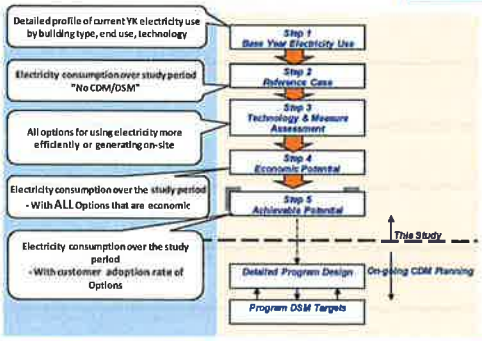
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Yukon CPR

Study Work Plan – 5 Steps

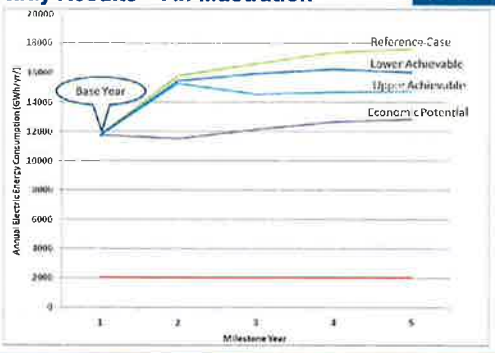
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Yukon CPR

Study Results – An illustration

ICF Marbek



Yukon CPR

Schedule (tentative)



- Start up Meetings – May 2,3,4
- Revised Workplan – w/o May 9
- REUS & Sales Date rec'd – w/o May 30
- Phase 1 Reports – July 22
- Phase 2 Reports – Sept 22
- Achievable Potential Workshops – w/o Oct 24
- Draft Final Reports – w/o Nov 21

Yukon CPR

Working Together - Client Roles



We know you are busy!

...But, the CPR needs your contributions.

Our proposed roles for you:

- Help us access best possible existing data
- Participate in bi-weekly teleconference
  - Regular day and time each week; enables all parties to remain up to date on CPR status, ability to quickly make decisions affecting scope, assumptions and timing.
- Review interim deliverables

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Questions/Suggestions?



Yukon CPR

Residential Sector

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Residential Topics

ICF Marbek

- Proposed segmentation – sub sectors and end uses
- Preliminary technologies
- Models
- Data needs and sources; gaps or issues

- Examples of outputs & applications – all sectors

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Climate region
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type → Detached, Attached, Low-rise apartment, Mobile/Other
- Vintage
- Supply system
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage → Before major code change, After major code change, New construction
- Supply system
- Dominant heating fuel

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Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system → Grid-connected, Diesel community
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system
- Dominant heating fuel → Electricity, Fossil

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End Uses

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- Space heating
- Domestic water heaters
- Lighting
- Refrigerators
- Freezers
- Cooking appliances
- Washing machines
- Clothes dryers
- Dishwashers
- Fireplaces
- Spa heaters
- Televisions & home entertainment electronics
- Set top boxes
- Computers and peripherals
- Small appliances
- Elevators
- Other

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Preliminary Technology List

- Heating: Shell Measures (Existing)
  - Attic Insulation
  - Wall Insulation
  - Slab Insulation (Unfinished Basements)
  - Basement (Foundation) Insulation
  - Crawl Space Insulation
  - Air Sealing/Weather Stripping/Caulking
  - High-Performance (ENERGY STAR™) Windows
  - Super High-Performance Windows
  - Air Leakage Sealing and Insulation (Old Homes)
- Heating: Shell (New Homes)
  - High-Performance Homes (EGH80 /R2000/ENERGY STAR™)
  - LEED Certified Apartment Buildings

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Preliminary Technology List

- Heating: Equipment
  - Air Source Heat Pumps
  - Ground Source Heat Pumps (Open Loop)
  - Ground Source Heat Pumps (Closed Loop)
  - Programmable Thermostats (Central Heating)
  - Programmable Thermostats (Baseboard Heating)
  - Solar Pre-Heated Make-Up Air Systems (e.g., SolarWall™)
  - High Efficiency Heat Recovery Ventilators (HRVs)
- Water Heating
  - Active Solar Water Heating Systems
  - Point-of-Use Water Heaters (Electric)
  - DHW Tank Insulation
  - DHW Pipe Insulation
  - Ultra Low-Flow Showerheads
  - Wastewater Heat Recovery Systems
  - DHW Recirculation Systems (e.g. Metlund D'MAND™)

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Preliminary Technology List

- Appliances
  - ENERGY STAR Dehumidifiers
  - Convection Ovens – Electric
  - High Efficiency (ENERGY STAR™) Refrigerators
  - High Efficiency (ENERGY STAR™) Freezers
  - High Efficiency (ENERGY STAR™) Front Loading Clothes Washers
  - High Efficiency (ENERGY STAR™) Top Loading Clothes Washers
  - High Efficiency (ENERGY STAR™) Dishwashers
- Lighting
  - Compact Fluorescent Lamps (CFL) – Indoor
  - Compact Fluorescent Lamps (CFL) – Outdoor
  - Dimmable Compact Fluorescent Lamps
  - LED Lamps
  - LED Holiday Lighting (Indoor)
  - LED Holiday Lighting (Outdoor)
  - Efficient Fluorescent Lamps (Replace T12s with T8s)
  - Motion Detectors and Timers for Outdoor Lighting
  - Motion Detectors and Timers for Indoor Lighting

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Preliminary Technology List

- Other
  - Spa Pump Timers
  - High Efficiency Spa Pumps
  - Insulating Spa Covers
  - Heat Pump Spa Heaters
  - Solar Spa Preheat
  - Timer/Thermostat for Block Heaters
  - Energy Efficient (ENERGY STAR™) Printers and Faxes
  - Energy Efficient (ENERGY STAR™) LCD Televisions
  - Smart Power Bars (Computers and Peripherals)
  - Smart Power Bars (Televisions and Home Entertainment)

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Models

- Hot-2000
  - Commercially supported software developed by the Federal government
  - Calculates *net* heating, cooling and hot water loads for homes including consideration of *cross effects*
  - Provides energy use intensity inputs into the macro model (RSEEM)
  - Used to develop a *tuned* house model matched to both what we know of Yukon construction and the energy sales data provided by the utility
  - The resulting model can be used to estimate the impacts of shell improvements

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Models

- RSEEM
  - An Excel-based *accounting* model
  - Is not a *predictive* model
  - Does all of the necessary arithmetic to calculate the energy consumption in each combination of building type, end-use, milestone year and supply system type for each scenario
  - Generates pivot-table-ready output for maximum flexibility in producing tables and charts needed by the client

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Data

ICF Marbek

- Needs
  - Fuel share data for space and water heating – current and forecast
  - Appliance saturation data, by dwelling type
  - Forecast growth in housing stock and electricity use, by dwelling type
  - Residential energy audit results – typical insulation levels, window type, building condition, etc.
  - Studies on new construction practices
  - Studies on appliance use, both current and over the forecast period
  - Known territorial changes/dates to building energy performance standard, planned or historical

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Data

ICF Marbek

- Sources
  - Sales data
  - Residential End Use Surveys (forthcoming)
  - Load Forecast
  - Yukon Housing Corporation
  - EnerGuide for Housing database etc.
  - Market or other studies
  - Reports documenting Yukon-specific conditions
- Gaps or issues?

Yukon CPR Kickoff

Outputs – All Sectors*

ICF Marbek

- Reports
  - Built up section by section as the phases of the project proceed
  - Opportunity to review, comment, and participate as we go
- Measure Analysis Model
  - Client can experiment with assumptions to see what changes occur
- Data Management Tool
  - Used by Marbek to make report exhibits
  - Client can manipulate study data to answer other questions

* Outputs vary somewhat by sector, to accommodate different needs.

Yukon CPR Kickoff

Measure Analysis Model

ICF Marbek

NB POWER COMMERCIAL SECTOR ELECTRIC EFFICIENCY MEASURES

T5 High Intensity Fluorescent Systems

Description:	High-intensity discharge (HID) lighting such as metal halide is commonly
Baseline:	Standard 400 W metal halide - Ballst power = 461 W, 20,000 hr lamp life
Upgrade:	Upgrade is a fluorescent high bay fixture equipped with six F54T5 HO

Sub-sector		Low use (2000 hours/year)	Med use (3500 hours/year)	High use (5000 hours/year)
Baseline	Elec. (kWh/yr.)	922	1,614	2,305
Upgrade	Elec. (kWh/yr.)	740	1,295	1,850
Heating Penalty/	Elec., Total (kWh/yr.)	92.8	162.5	232.1
Peak Demand Factor (kWh/kW)		6,787	6,787	6,787
Annual Resource Savings	Elec. (kWh/yr.)	89	156	223
	Elec. (kW peak)	0.013	0.023	0.033
Cost Parameters	Upgrade, Material ($)	$250.00	$250.00	$250.00
	Upgrade, Installation ($)	$75.00	$75.00	$75.00
	Baseline, Material ($)	$245.00	$245.00	$245.00
	Baseline, Installation ($)	$60.00	$60.00	$60.00
	Total Measure Cost ($)	$20.00	$20.00	$20.00
	Basis (Full/Incr.)	Incr.	Incr.	Incr.

Yukon CPR Kickoff

Measure Analysis Model

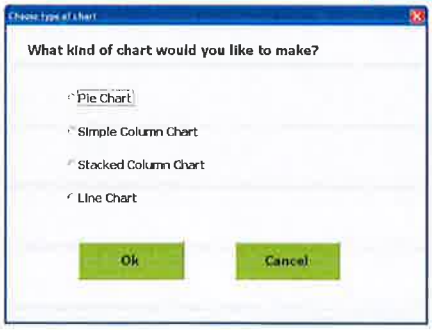
ICF Marbek

Cost Parameters	Upgrade, Material ($)	$250.00	$250.00	$250.00
	Upgrade, Installation ($)	$75.00	$75.00	$75.00
	Baseline, Material ($)	$245.00	$245.00	$245.00
	Baseline, Installation ($)	$60.00	$60.00	$60.00
	Total Measure Cost ($)	$20.00	$20.00	$20.00
	Basis (Full/Incr.)	Incr.	Incr.	Incr.
Incremental O&M ($/yr.)		$0.00	$0.00	$0.00
Lifetimes	Upgrade (yrs.)	16.0	16.0	16.0
	Baseline (yrs.)	16.0	16.0	16.0
Annual Savings ($/yr.)		$7.13	$12.48	$17.83
Simple Payback (yrs.)		2.8	1.6	1.1
NPV of O&M Costs ($)		$0.00	$0.00	$0.00
Total Benefits ($)	Electric Energy	$72.79	$127.38	$182
	Electric Demand	$0.00	$0.00	$0
Measure TRC ($)		$52.79	$107.38	$162
Benefit/Cost Ratio		3.64	6.37	9.10
Cost of Conserved Electricity (CCE) (¢/kWh)		2.53	1.45	1.01
Savings over Baseline	Elec.	19.7%	19.7%	19.7%
	w/ Elec.Htg. Penalty	9.7%	9.7%	9.7%

Yukon CPR Kickoff

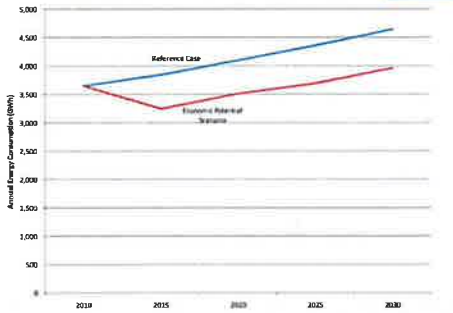
Data Management Deliverable

ICF Marbek



Yukon CPR Kickoff

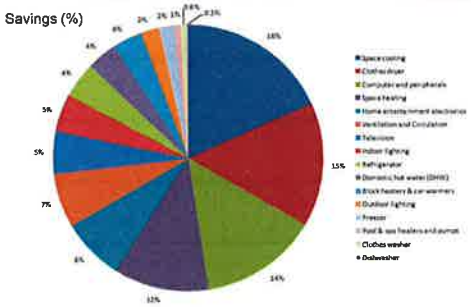
Data Manager: Scenario Comparison



* Results are from a Canadian electric utility study.

Yukon CPR Kickoff

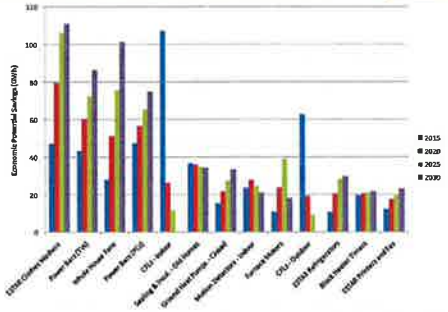
Data Manager: Results by End Use



* Results are from a Canadian electric utility study.

Yukon CPR Kickoff

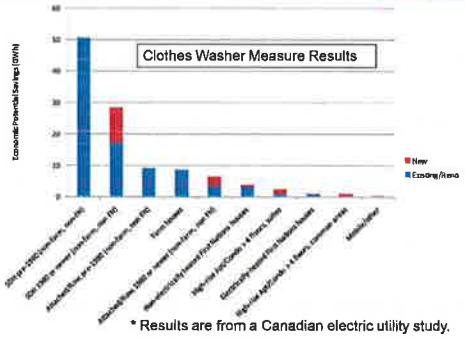
Data Manager: Results by Measure



* Results are from a Canadian electric utility study.

Yukon CPR Kickoff

Data Manager: Zero in on One Measure



* Results are from a Canadian electric utility study.

Questions/Suggestions?



Yukon CPR

Commercial Sector

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Commercial Topics

ICF Marbek

- Framework / methodology review
- Proposed segmentation – sub sectors and end uses
- Preliminary technology list
- Model overview
- Study outputs
- Data needs and sources; gaps or issues
- Discussion

Yukon CPR Kickoff

Methodology

ICF Marbek

- Start with C/I consumption (sales)



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Methodology

ICF Marbek

- Disaggregate into commercial sub sectors

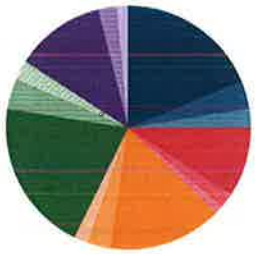


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Methodology

ICF Marbek

- Disaggregate subsector consumption by end use

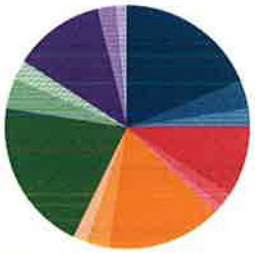


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Methodology

ICF Marbek

- Apply measures in various scenarios



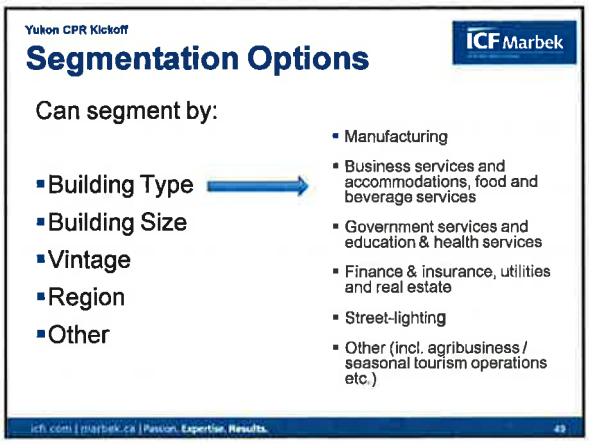
Yukon CPR Kickoff

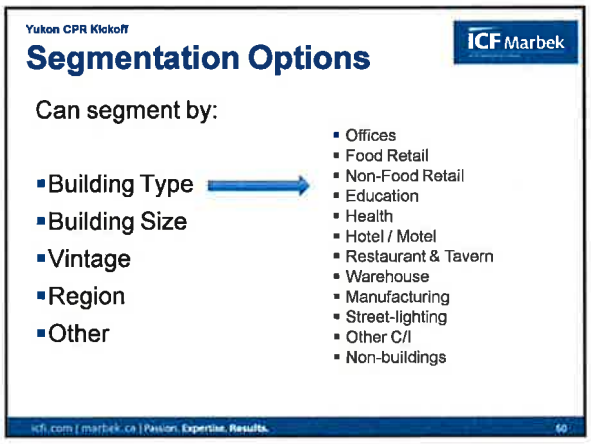
Segmentation Options

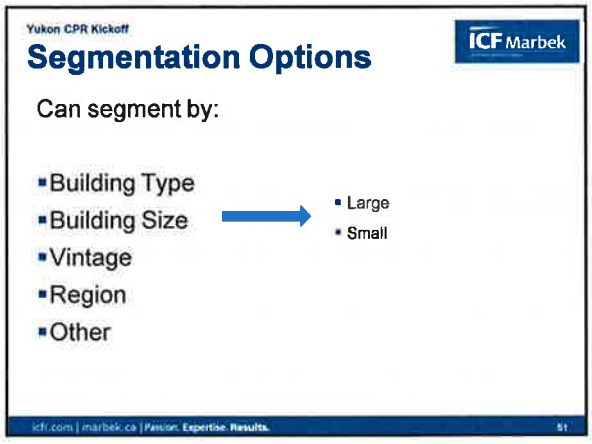
ICF Marbek

Can segment by:

- Building Type
- Building Size
- Vintage
- Region
- Other


Yukon CPR Kickoff
Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Manufacturing
Business services and accommodations, food and beverage services
Government services and education & health services
Finance & insurance, utilities and real estate
Street-lighting
Other (incl. agribusiness / seasonal tourism operations etc.)
icfi.com | marbek.ca | Passion. Expertise. Results.
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Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Offices
Food Retail
Non-Food Retail
Education
Health
Hotel / Motel
Restaurant & Tavern
Warehouse
Manufacturing
Street-lighting
Other C/I
Non-buildings
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Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Large
Small
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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- Building Size
- Vintage → Existing stock; New construction
- Region
- Other

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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- Building Size
- Vintage
- Region → Grid-connected; Diesel
- Other

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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- Building Size
- Vintage
- Region
- Other → Government Subset

Yukon CPR Kickoff

End Uses

- General Lighting
- Secondary Lighting
- High Bay Lighting
- Outdoor Lighting
- Space Heating
- Space Cooling
- HVAC Fans & Pumps
- Water Heating
- Computers & Office Equipment
- Other Plug Loads
- Cooking Equipment
- Refrigeration
- Elevators
- Miscellaneous
- Street Lighting

Yukon CPR Kickoff

Preliminary Technology List

Lighting

- Standard T8 Systems
- High-Performance T8 systems—Retrofit
- High-Performance T8 systems—Redesign
- Occupancy/Dimming Controls
- Induction Lamps
- Compact Fluorescent Lamps
- White LED Lamps
- Halogen Infra-red Lamps
- Ceramic Metal Halide Lamps
- Pulse-start Metal Halide Systems

Exterior Lighting

- Compact Fluorescent Lamps—Outdoor
- Pulse-start Metal Halide Systems—Outdoor
- Lighting Controls—Outdoor
- Efficient Street-lighting

Building Envelope

- High-performance Glazing
- Super High-performance Glazing
- Upgrade Wall Insulation
- Upgrade Roof Insulation
- Air Sealing

Yukon CPR Kickoff

Preliminary Technology List

Water Heating

- Low Flow Faucet Aerators
- Low-flow Showerheads
- Low-flow Pre-rinse Spray Valves
- Tank Insulation
- Drainwater Heat Recovery
- Solar Hot Water Heating Systems

Cooking

- High Efficiency Cooking Equipment

Refrigeration

- ENERGY STAR Refrigerators and Freezers
- Efficient Refrigeration—Full Cost Measures
- Efficient Refrigeration—Incremental Cost Measures

HVAC

- Low-Temp. Air-source Heat Pumps
- Ground-source Heat Pumps
- Infrared Heaters
- Air-to-air Heat Recovery
- H.E. Chillers
- H.E. Packaged DX Cooling
- Demand-controlled Ventilation
- Demand-controlled Kitchen Ventilation
- Solar Preheated Make-up Air
- Adjustable Speed Drives
- Premium Efficiency Motors
- Programmable Thermostats

Yukon CPR Kickoff

Preliminary Technology List

ICF Marbek

Whole Building Measures

Retro-commissioning
Advanced Building Automation Systems

New Buildings

New—25% better than Current Design Practice
New—40% better than Current Design Practice
New—60% better than Current Design Practice

Yukon CPR Kickoff

Models

ICF Marbek

CEEAM

- Marbek's in-house building energy modelling platform, developed in conjunction with NRCan.
- Used to develop building archetypes for each commercial subsector based on:
  - What we know about the Yukon building stock
  - Information gathered from other jurisdictions
  - Sales data & other data provided by the utility
  - Other sources

Yukon CPR Kickoff

Models

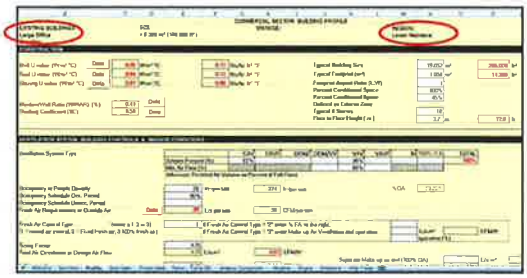
ICF Marbek

CEEAM (cont.)

- Provides energy use intensity inputs into the macro model (CSEEM)
- Used as a tool to evaluate individual energy efficiency measures, particularly those affecting the building shell

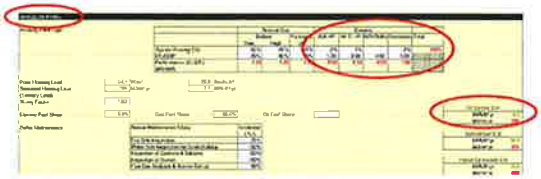
Yukon CPR Kickoff

Models - CEEAM



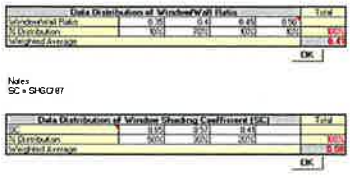
Yukon CPR Kickoff

Models - CEEAM



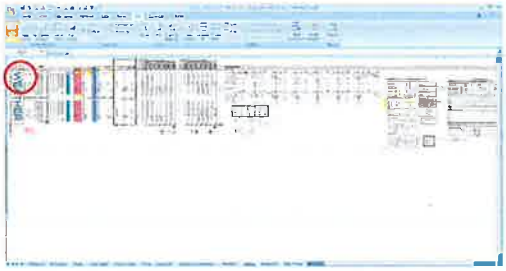
Yukon CPR Kickoff

Models - CEEAM



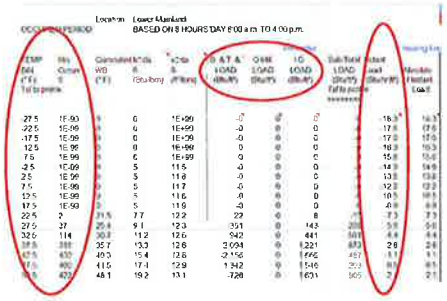
Yukon CPR Kickoff

Models - CEEAM



Yukon CPR Kickoff

Models - CEEAM



Yukon CPR Kickoff

Models - CEEAM



Yukon CPR Kickoff

Models

ICF Marbek

HOT-2000

- Potential option for modelling sub sectors in which buildings tend to be small.

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Models

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CSEEM

- An Excel-based *accounting* model
- Is not a *predictive* model
- Does all of the necessary arithmetic to calculate the energy consumption in each combination of building type, end-use, milestone year and supply system type for each scenario
- Generates pivot-table-ready output for maximum flexibility in producing tables and charts needed by the client

Yukon CPR Kickoff

Outputs

ICF Marbek

- Reports
  - Built up section by section as the phases of the project proceed
  - Opportunity to review, comment, and participate as we go
- Measure Analysis Model
  - Client can experiment with assumptions to see what changes occur
- Data Management Tool
  - Used by Marbek to make report exhibits
  - Client can manipulate study data to answer other questions

Yukon CPR Kickoff

Data

- Needs
  - Fuel share data for space and water heating – current and forecast
  - A/C saturation data, by building type
  - Forecast growth in building stock and electricity use, by sub sector
  - Commercial survey / energy audit results – typical insulation levels, glazing type, lighting equipment, building condition, etc.
  - Studies on new construction practices
  - Changes to building energy performance standards, planned or historical
  - Floor area data

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Data, continued

- Sources
  - Sales data
  - Yukon Energy Strategic Plan 2010-2012
  - Current load forecast
  - Market or other studies
  - Reports documenting Yukon-specific conditions
- Gaps or issues?

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Questions/Suggestions?



Yukon CPR

Customer-side Renewable Energy

Yukon CPR

Customer-side Renewable Energy

Scope

- Small scale, renewable, customer-side of the meter

Proposed Technologies

- Solar hot water heating (offsetting electrically heated hot water)
- Solar PV
- Small-scale wind (less likely to be cost effective than the solar choices)

Yukon CPR

Customer-side Renewable Energy

Information Needs

- Information on current Yukon programs and policies that support small scale renewable energy
- Information on existing Yukon small-scale renewable installations
- Typical Yukon installation sizes and characteristics, if available
- Contact information for leading renewable industry installers, researchers and proponents within Yukon

Yukon CPR

Customer-side Renewable Energy

ICF Marbek

Next Steps

- Ruth Urban is team lead
- This meeting - Establish client contact(s) for CSRE
- Post meeting - Teleconference to initiate this study component



Yukon CPR
Peak Demand (Capacity)

Yukon CPR

Peak Period (Capacity)

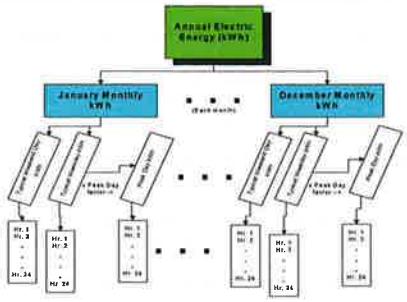
ICF Marbek

- **Step 1 – Define Peak Period(s) of Interest**
- **Example from previous study:**
  - **Peak Period #1: Annual System Peak Hour** –e.g., the hour ending at 7 pm on a day in December; it is highly correlated with the coldest day of the year when occurring in December.
  - **Peak Period #2: Annual Weekday System Peak Period** – The 5-9 pm period on the coldest day of the year when occurring in December.
  - **Peak Period #3: Annual Weekend System Peak Period** – The 5-9 pm period on the coldest weekend day of the year when occurring in December.
  - **Peak Period #4: Annual Peak Energy** – This uses the peak hours of 7am through 10pm on all weekday non-holidays during the year.

Yukon CPR

Peak Period Approach

- Step 2 – Allocate Annual Electricity Use for each facility type and end use



Yukon CPR

Peak Period Approach
Sample Output – For illustration only

Dwelling Types	Period 1 Peak Hour	Period 2 Week Day Peak Period	Period 3 Weekend Peak Period	Period 4 Peak Energy
Single Detached Houses	666	658	610	330
Attached/flow Houses	99	97	89	50
Farm Houses	91	91	85	49
First Nations Housing	62	61	53	26
Apartment/Condo Buildings	22	22	22	8
Mobile/Other	0	0	0	0
Grand Total	941	930	860	463

Yukon CPR

Peak Period (Capacity)

Next Step

- Joe Lopes is team lead
- This Meeting -Establish client contact(s) for peak period
- Post Meeting -Follow up teleconference to initiate this study component

ICF Marbek

Questions/Suggestions?

ICF Marbek

Thank You !

DSM Community Visit Schedule
Wednesday May 4 and Thursday May 5, 2011

DATE	LOCATION	DETAILS
Wednesday May 4		
8:00 am	Depart Whitehorse	Leaving from High Country Inn
9:30 am	Arrive Haines Junction	Meet at Village Office to coordinate sites visit
10:15 am	Alcan Inn	No guide for visit, have been invited to look around…requested to notify Talise of our arrival
10:30 am	Community drive around	
11:00 am	Lunch	
11:30 am	Depart for Burwash Landing	
1:30 pm	Arrive Burwash Landing	
1:30 pm	Meet at Public Works Building (Kluane First Nation)	Meet Joe Bruneau 867-841-4200 Drive through town, go past the admin building. Take first right after, up the road until you see a blue trailer and blue shop…in blue shop.
2:00 pm	Community drive around	
2:20 pm	Depart for Destruction Bay	
2:40 pm	Arrive Destruction Bay	
2:40 pm	Community drive around	
3:00 pm	Depart for Haines Junction	
4:45 pm	Arrive Haines Junction	
4:45 pm	Kluane Park Inn	Alicen is the contact, happy to have us view the bar (café isn't open yet)
5:15 pm	Depart for Whitehorse	
6:45 pm	Arrive Whitehorse	High Country Inn
Thursday May 5		
9:20 am	Pick-up to start tour	
9:30 am	Canada Games Centre – 200 Hamilton Blvd	Meet Art Manhire, manager of indoor facilities
10:00 am	City of Whitehorse Municipal Service Building - 4210 Fourth Avenue	Meet Larry Shipman, Engineering (867-668-8304)
10:45 am	YECL Building – 1100 1st Avenue	
11:00 am	Hougan Centre Tour – 305 Main Street	Meet Terry Shipman, property manager - 333-9929
12:00 pm	Lunch	
1:30 pm	Government of Yukon facility - Supply Service's and Stores –	Yukon Government – Jim MacPherson, Engineer Foreman

	Industrial park (Enter at central workshop compound – Bldg #1277	(cell 667-3073)
2:00 pm	Government of Yukon facility - Law Centre – 3rd Avenue	Jim will follow
3:30 pm	Arrive Jack Hulland School – 1304 Fir Street	Meet David Black, Environmental Coordinator Department of Education
4:00 pm	Finish tour day	

Demand Side Management Inititiative

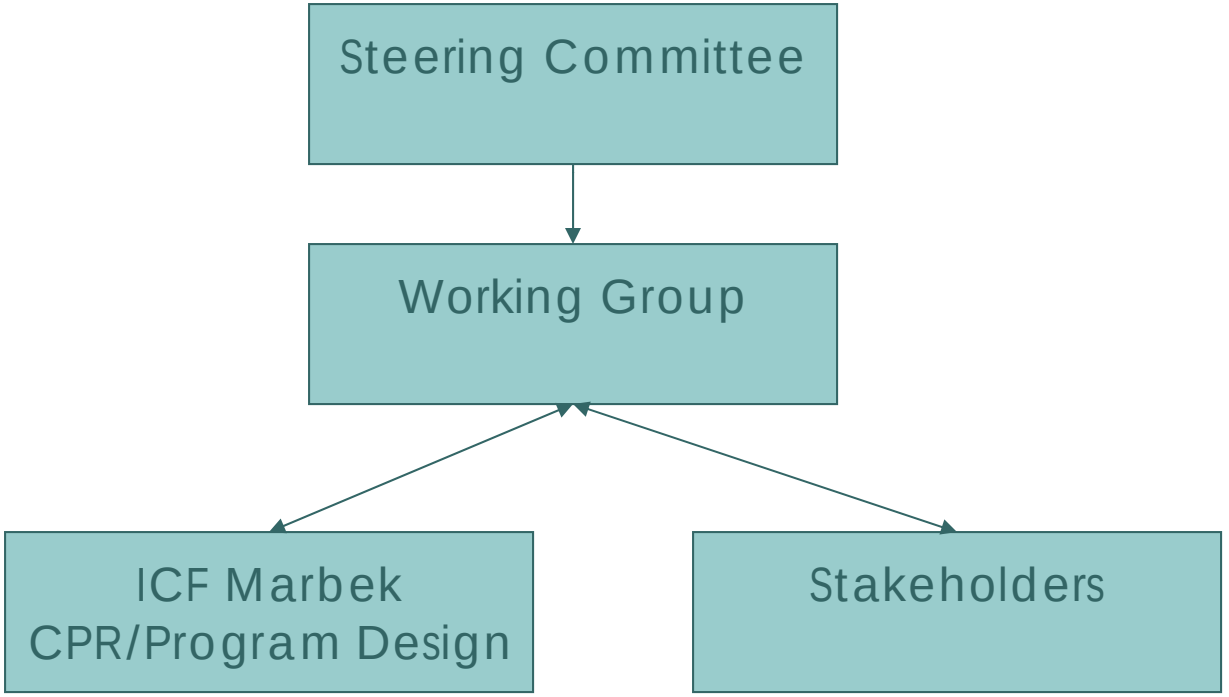
Yukon Energy Charrette

April 19, 2012

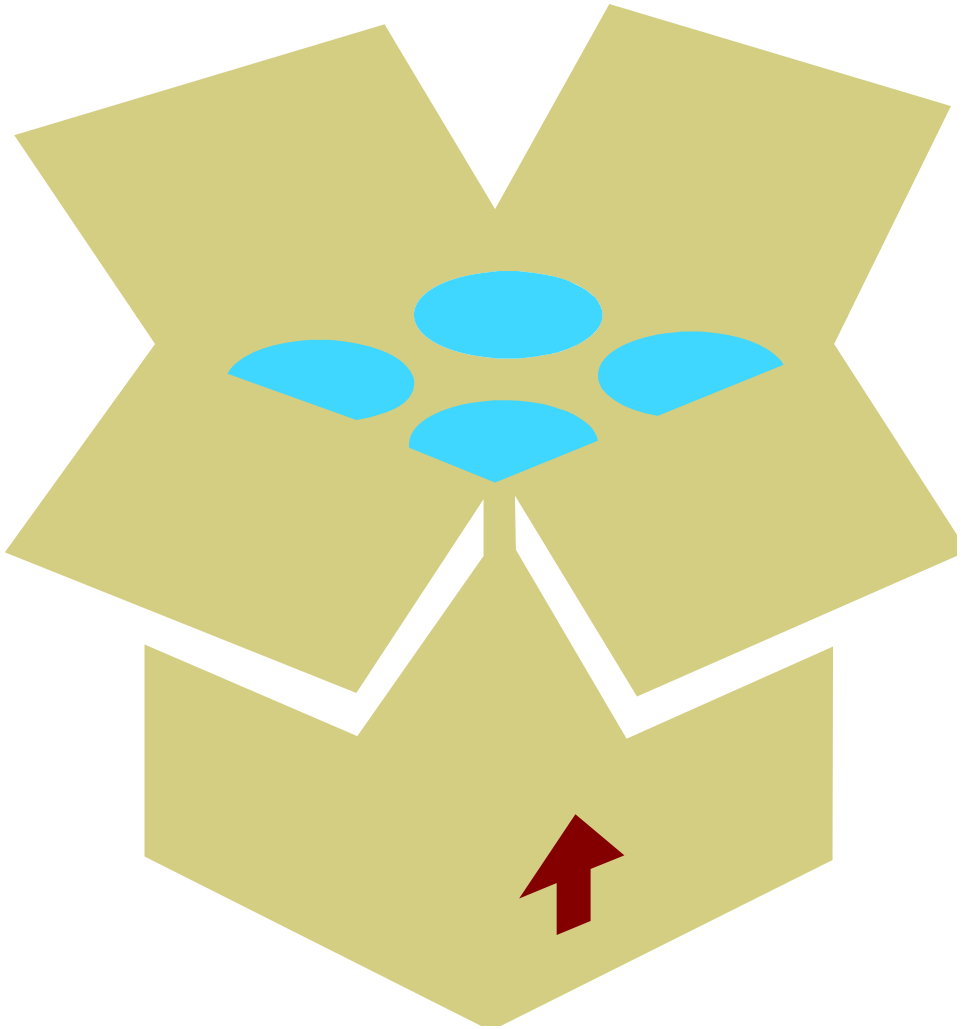
Demand Side Management Drivers

- Yukon Utility Board Orders
- Energy Strategy for Yukon
- Growth in the territory (All sectors)
- Increased reliance on diesel generation

Demand Side Management Partners



The Electrical Box



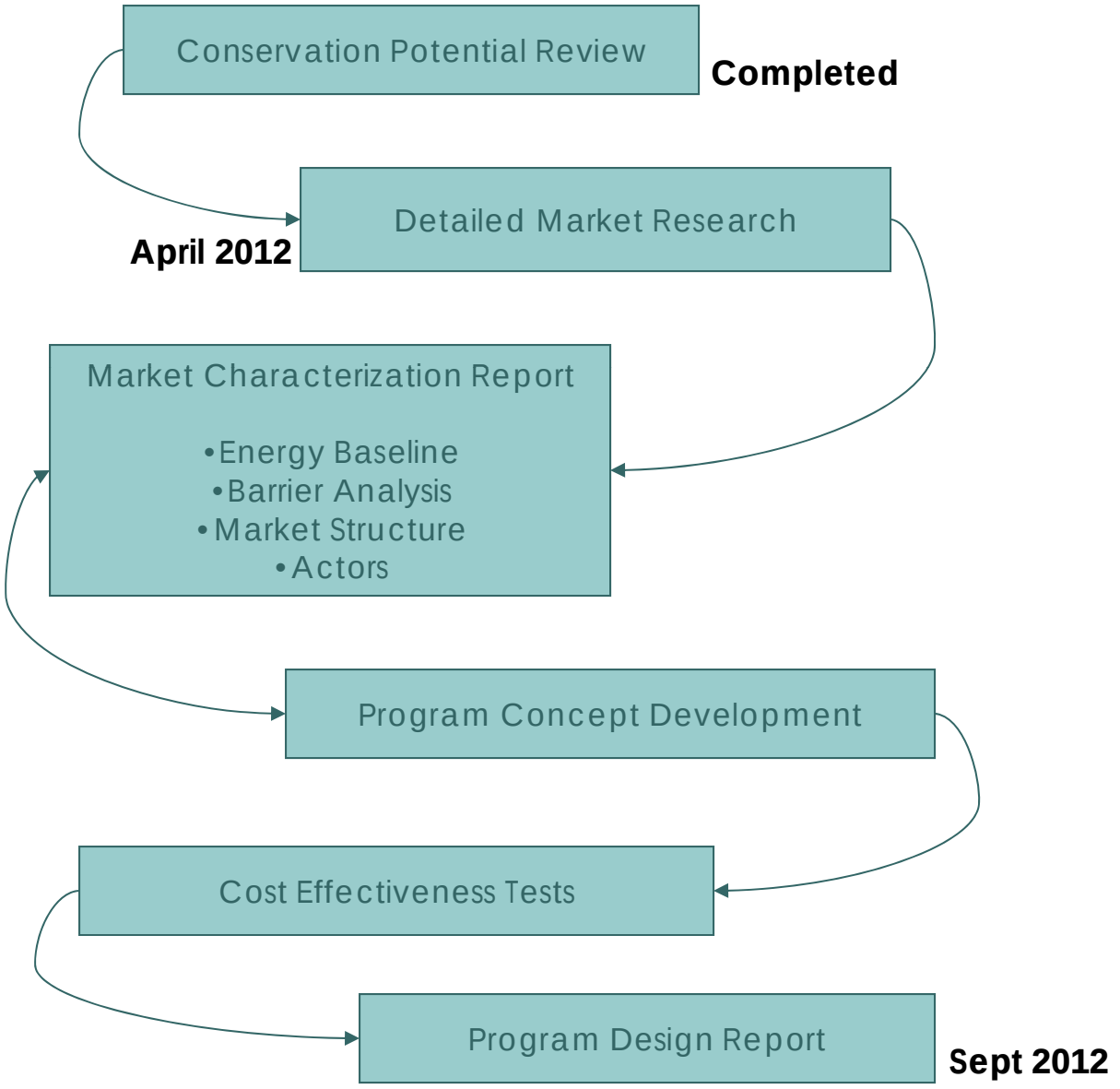
Conservation Potential Review

- Reference point:
  - Residential
  - Commercial/Institutional
  - Customer-side renewable options
- Base year established using actual data for 2010
- Forecast consumption to 2030 with benchmarks every 5 years

Other Initiatives Completed

- Community Engagement
- Residential End Use Study
- LED Streetlight Pilot
- Awareness Building
- Net-Metering
- On-going Energy Solution Centre

Detailed Program Design



Next Steps

- Reduction Targets
- DSM Framework and Plan Delivery
- Customer Engagement
- Submission to Yukon Utility Board

YUKON ENERGY

Energy Conservation Workshop Report



April 19, 2012

1. Introduction

At the Yukon Energy Charrette in March 2011, Yukon Energy brought together governments, Yukoners and energy experts from across Canada for three days to discuss and share information on resource options for Yukon's energy future. One of the key outcomes from the charrette was Yukon Energy's commitment to continue engaging stakeholders, governments and the public in planning for the future. To meet that commitment and plan in public, Yukon Energy is holding energy workshops on a series of topics and resource options. The Energy Conservation Workshop is Yukon Energy's fourth workshop.

The information gathered from the workshops and public meetings is being used to inform and direct the work of Yukon Energy and its consultants in carrying out the resource options planning. The information gathered from this workshop will also be used by the Demand Side Management Working Group (YG, YECL, and YEC) to help them develop a conservation program in the Yukon as directed by the Yukon Utilities Board (see Drivers of Demand Side Management Presentation on YEC website).

This is the report from the Energy Conservation Workshop and Public Meeting held on April 19th, 2012 in Whitehorse.

2. Workshop Objectives

The workshop objectives were developed with Yukon Energy and their partners. The workshop partners were: Yukon Electrical Company Ltd, Energy Mines and Resources, (Yukon Government), Yukon Conservation Society, the Yukon Utilities Consumer Group and Alexco Resources. The partners contributed their expertise and were supported by consultants from Morrison Hershfield Engineering, ICF Marbek and John Streicker. The objectives that guided the workshop were:

1. Examine energy conservation in the context of the YEC planning principles and 20-Year Draft Resource Plan;
2. Identify the environmental and socio-economic issues and opportunities in relation to energy conservation in Yukon;
3. Educate the participants as to conversation potential and opportunities;
4. Understand the regulatory framework in which the Demand Side Management (DSM) Working Group has been working; and,
5. Obtain feedback from participants on how to deliver successful energy conservation programs.

3. Workshop Participants

Over 65 invited and interested workshop participants attended the half day session. Participants represented the following stakeholders, governments and industry:

Yukon Energy Corporation

Yukon Electrical Company Ltd.

Kwanlin Dun First Nation

The Village of Carcross

City of Whitehorse

Alexco Resources

Champagne Aishihik First Nation

Yukon Conservation Society

Tipping Point Strategies

Association of Yukon Communities

Yukon Utilities Consumer Group

Government of Yukon (Highways and Public Works Property Management Division, Energy Solutions Centre, Energy Mines and Resources, Department of Education, HPW Capital Development, Climate Change Secretariat)

Yukon Environmental and Socio-Economic Assessment Board

Town of Watson

Green Heat Technologies Ltd.

Northerm Windows and Doors

Narrow Gauge Construction

ICF Marbek

Northern Climate Exchange

Yukon Development Corporation

Village of Carmacks

Leading Edge Projects

Whitehorse Chamber of Commerce

Yukon Cold Climate Innovation Centre

The workshop was also attended by Yukon Energy staff and consultants.

4. Presentations

The workshop provided the opportunity for Yukon Energy to share the findings from the Conservation Potential Review with the participants as well as for key stakeholders, partners and governments to present their information. The following presentations were delivered at the workshop and are posted on the Yukon Energy website at www.yukonenergy.ca/energy/public_engagement/energyworkshop/.

a) ***Why Demand Side Management?*** John Streicker, P.Eng., Science Advisor and Climate Change Expert, Northern Climate Exchange, Yukon College.

b) ***Drivers of Demand Side Management in the Yukon.*** Jessica Thiessen, Manager Energy Conservation.
c) ***Results from Conservation Potential Review***. Paul Robillard, Director, ICF Marbek.
d) ***Alexco Demand Side Management & Audit Review.*** Peter Johnson, Construction Manager, Alexco Resources.
e) ***Utilities Consumers' Group Demand Side Management Presentation.*** Roger Rondeau, Yukon Utility Consumers Group.
f) ***Building a Culture of Conservation Beyond the Utilities.*** Anne Middler, Energy Coordinator, Yukon Conservation Society.

5. Workshop

Following the presentations the participants were organized into facilitated groups ranging from 6 to 8 people. The groups were asked to discuss and record their ideas and comments with the intention of the work being shared with the participants, the public and included in the Yukon Energy's resource planning activities and the Demand Side Management Working Group's planning and program design work. This work with also be used to inform the ongoing resource planning work.

The participants were asked to report on the following questions that are related to how to deliver successful energy conservation programs:

1. **Who needs to be involved in the delivery of conservation programs?**

    - Who should be Involved?
    - What are the barriers?
    - What are the opportunities?

2. **What is the role of the Utilities and government in delivering conservation programs?**
3. **What is the community's role in ensuring conservation programs are successful?**
4. **What groups/organizations currently exist that can facilitate the delivery of conservation programs? How should they be engaged?**
5. **How can existing groups and interested individuals work to integrate electricity efficiency and conservation into their broader community based conservation initiatives?**

Results

The following is a summary from the workshop and public meeting.

Involvement in Delivery of Conservation Programs

Conservation programs should involve:

- Consumers, utilities, developers, trades, large users, industrial sector, commercial sector, supply chain actors, all levels of government, Yukon Housing, chambers of commerce, professional organisations, non-governmental organisations, Utilities' Consumers Group, Yukon Conservation Society, Yukon College, children, education system, technology suppliers, implementers representing successful programs from outside Yukon.

Potential barriers include:

- Information is non-existent (the public doesn't know how electricity is used), information can be hard to find, there can be too much information, or it can be confusing.
- Communities do not have the financial resources within their regular budgets to implement/pay for programs.
- Politicians need to make financial commitments in the short term to realise benefits over the long term.
- Lifecycle costing is not part of personal product purchasing decisions.
- Programs adopted from elsewhere may be ineffective in the northern context.
- There are currently no incentive policies for energy time of day pricing, audits, loans and grants.
- DSM resources and programs are Whitehorse centric.
- There is a suspicion of new technology.
- The public does not understand what the motivation of public utilities is.
- There is ratepayer skepticism because it is the business case of the utility to sell electricity.
- There are limited options and incentives currently available to implement energy conservation programs.
- Resistance to change and mindsets of public, corporations and government - apathy, too easy to not be part of the solution, and perceptions "nothing I can do would make a difference".
- Understanding and considering the impact of programs, peak saving versus total electricity reductions.
- Obtaining sustained user change, needs to be mainstreamed and not an add-on.
- There may be a loss of incentive for conservation if excess capacity becomes available.
- Billing systems for industrial customers – hard to coordinate load on 9 different systems/invoices.
- Current metering and pricing signals is a barrier.

- There are no incentives for landlords or tenants to conserve depending on who pays utility bill.
- Industry backlash.

Potential Opportunities Include:

- Saving energy and money.
- Develop partnerships among all energy users, utilities, and policy makers.
- Develop different programs and priorities for different communities (one size does not fit all).
- Personalise achievements toward targets/progress
- Work with First Nations to build capacity and adopt programs.
- Create a rewards system for groups implementing DSM to provide incentives for industrial customer, energy performance contracts.
- Identify user classes and tailor programs/incentives to each group.
- Offer energy conservation programs at Yukon College and as part of the trades programs.
- Include in the public school curriculum.
- Implement seasonal rates.
- Examine the applicability of smart meters.
- Complete the net metering policy to encourage distributed energy which would allow the promotion of rooftop solar PV and solar thermal.
- Jobs from the development of a building retrofit program.
- Use social marketing and the local media to promote energy efficiency.
- Energy performance contracts with users.
- Public education - show consequences of no DSM, make electricity use more visible.
- Public product education e.g. promote most efficient energuide products, standardised labelling, energy labelling of housing, choice editing, develop web-based tool to assist in lifecycle costing etc.
- Yukon Utility Board should look at costs of all energy sources not just electricity rates to promote conservation for all energy sources, not just electricity.
- Develop a simplified one stop shop for information and program delivery that is flexible and reflects Yukon's diversity.
- Encourage ground-source heat pump for peak shaving.
- Encourage YG and the City of Whitehorse to develop energy efficient building codes.

Utilities and Government's Roles and Responsibilities in Delivering Conservation Programs:

Utilities should:

- Develop, implement, and evaluate conservation programs.
- Educate the public and stakeholders on need for conservation and programs and work with them in developing programs.

- Require large customers implement energy efficiency measures, have best practices in place.
- Track electrical usage in sample groups for each sector. Share usage and supply data with partners to help recognise and implement energy efficiency opportunities. Use information available on energy usage to outline feasibility and impact of actions so that government can provide policy support for implement programs. Use product knowledge to educate and create programs that encourage consumers to choose most efficient products.
- Promote early adopters by providing some good PR and provide awards for outstanding performance. Provide a report card on effectiveness of conservation programs that promotes accountability, raises public awareness, and gives opportunity for community input

Yukon Territorial Government should:

- Need to lead by example, promote conservation in the schools and curriculum (K-12).
- Provide programs for professions and trades in fields that support energy conservations.
- Policy development such as climate action plan, energy plan, and climate adaptation plan and adopt GHG, renewable energy, and energy conservation targets. Implement a net metering program. Direct the utility to achieve conservation targets and implement programs.
- Enable utilities to implement conservation programs. Encourage economic development in support of conservation (innovation, incentives, and policies).
- Mandate energy efficiency in codes.
- Target policies to groups and sectors such as government users, rate payers, mines, low income, renters/landlords, and developers.
- Reward innovation.

Municipal Governments should:

- Lead by example and be early adopters.
- Enact complementary codes, by-laws, tax incentives, and planning practices (planning with consumption in mind) that promote conservation.
- Reward innovation.
- Show vision in the community plan and money will come in support of that vision. Remind the community of that vision.

First Nations should:

- Lead by example.
- Could provide economic development opportunities.

The community's roles in ensuring conservation programs are successful

The community should:

- Create a culture of conservation with participation from everyone in all sectors.
- Shift culture from instant gratification to long term savings.
- Maintain in the long term the awareness for the need to conserve.
- Be watch dogs to the utilities and government.
- Be a source of ideas.
- Challenge or complete with other communities to obtain energy reductions.

Existing Groups/organizations that can facilitate the delivery of conservation programs and how they should be engaged?

Consumers should:

- Participate in the program design.
- Be provided with information to make choices that reduce electricity consumption.
- Have tools to help them understand lifecycle cost savings.
- Take responsibility in their energy use through behaviour change and be held accountable.
- Be educated of peak usage so they can adjust consumption to be part of the solution.

Industrial users should:

- Be role models, by providing leadership by making long-term investments in energy efficiency.
- Be involved in the development of conservation program planning.
- Reward employees for green ideas.
- Help make the business case for conservation work.
- Evaluate/audit designs of projects and buildings at the design stage to maximise economic opportunities for efficiency.

Developers should:

- Have state of the art energy efficiency in new buildings.
- Think of conservation at the design stage.

Chambers of Commerce/Private Sector should:

- Help developers, and private sector businesses to be ambassadors for energy efficiency and feed information to government and utilities in conservation program design.
- Test potential programs.
- Provide expertise to recognise and implement opportunities.
- Be role models and reward employees for green ideas.

- Have retailers carry products that promote energy conservation as well as adopt best practices.

Yukon College and Yukon Cold Climate Innovation Centre should:

- Lead by example and become early adopters.
- Offer courses and research related to conservation opportunities in the northern climate.
- Launch pilot projects in implementing conservation measures and to test new technology.

Schools should:

- Lead by example and become early adopters.
- Teach energy literacy and awareness of conservation to children as a means to bring culture of conservation to the community similar to the recycling message.
- Provide energy usage and conservation assignments for children to bring home.

Non-governmental organisations should:

- Provide advocacy and be a watchdog.
- Fill in knowledge gaps.
- Ensure that programs are equitable.
- Provide assistance in program delivery, particularly n remote communities.

Energy Solutions Centre should:

- Support program delivery, provide program funding, and provide resources on examples of energy efficiency.

Yukon Housing should:

- As building experts, promote more energy efficient building standards.

6. Summary

The workshop participants recognise that conservation is an important part of meeting future energy needs. For energy conservation to be successful it requires involvement by all individuals and organisations. First and foremost, both the utilities and all governments must be role models for energy conservation. This means they should work together to promote energy efficiency and be early adopters.

Yukon Energy Corporation and Yukon Electrical Company Ltd. who hold the information on energy usage have the data to help develop programs for all sectors as well has provide a resource to customers on energy usage. The governments and the utilities need to work together and share information to inform government and utility policies, regulations, practises

and opportunities. The governments need to provide the utilities the policy tools to enable them to provide effective energy conservation programs. The utilities, with their understanding of energy planning need to inform the governments of the conservation opportunities and the resources required. There is also an opportunity for Yukon College and the Northern Research Center's Cold Climate Innovation group, NGOs and the private sector to provide technical input on what types of programs should be adopted. Government energy, greenhouse gas reduction and renewable energy policies should be aligned with the mandates and objectives of the utilities. This also includes green procurement, building codes, investment, and pricing signals. Programs should be tailored based on usage patterns and requirements of particular sectors. The utilities should be able to monitor the effectiveness of programs, adjust programs based on effectiveness, provide accountability, and ensure sustained promotion of energy conservation programs. Successful programs from elsewhere should be looked at as a starting point; however, their effectiveness needs to be evaluated in the northern context.

There is a need for capacity building including consumer education of energy efficiency products, training opportunities for trades in conservation fields, research and piloting in the application of technologies and programs in the north. In particular, there is a significant opportunity within the school system to provide students with energy literacy which could enable them to bring conservation home. Programs need to be equitable to both low-income and renters. Governments can provide financial and policy support to overcome these barriers.

Information needs to be available to consumers on the lifecycle costs of products, choices and initiatives to enable the government, industry, purchasers, and ratepayers to make energy conservation choices understanding the full cost of their decisions. Governments need to plan long term and consider the life cycle costs and opportunities of their choices. Financial institutions should also be encouraged to recognise the long term benefits of energy efficient choices and develop programs with long term benefits in mind.

It is important that conservation includes industry and does not appear to target only consumers. There is an opportunity for industry to be leaders by adopting best practices in energy efficiency both in looking to existing operation and equipment and in the design development stages of projects. All sectors can learn from such successes.

Overall, the key to success of an effective conservation program is knowledge and the development of a culture of conservation. Everyone should be aware of the impact of energy usage and be an active participant in the effort to conserve. Leadership by governments, utilities, businesses, utilities, and individuals to this mandate will ensure effective and enduring reductions in energy demand.

Yukon Energy thanks all those that participated in the workshop and public meeting. The presentations from the workshop experts along with the responses to the workshop questions are being incorporated into the development of Yukon Energy's energy conservation programs. Yukon Energy is committed to working with its partners, sharing information and to keep talking.

Demand Side Management Paper for the Energy Conservation Workshop, April 19, 2012

Prepared by Morrison Hershfield for Yukon Energy

1.0 Introduction

Energy conservation and efficiencies, referred to in the utility industry as demand side management (DSM), provides opportunities in Yukon to meet future energy requirements by reducing the need to construct additional electricity generation capacity. DSM includes both decreasing the total electricity demand and shifting the demand by changing when electricity is used. In both cases the cost of constructing new electricity generation capacity is avoided. DSM maximizes the use of the existing installed capacity. As such, DSM meets Yukon Energy's energy planning principles of reliability, affordability, flexibility, and environmental responsibility.

Direction from the Yukon Utilities Board, public responses (survey and energy charrette) and alignment with the Yukon government's Energy Strategy and Yukon Energy's corporate priorities means that an effective and robust DSM program is a crucial element in Yukon Energy's energy resource planning. According to a recently completed Conservation Potential Review conducted for the territory's two utilities and the Yukon government, it has been estimated that by 2030, DSM has the potential to save up to 48% of projected residential and commercial electricity demand growth on the Yukon grid.[1]

Direction from the Yukon Utilities Board, public responses (survey and energy charrette) and alignment with Yukon Government's Energy Strategy and Yukon Energy's corporate priorities has resulted in ensuring that an effective and robust DSM program is considered when forecasting Yukon's energy and capacity requirements over the next twenty years. Yukon Energy is also working to reduce its own energy consumption through Supply Side Enhancements (i.e. improved efficiency of generation units, transmission, etc.) and internal corporate energy conservation and efficiency initiatives (changes to operations, procurement, staff behavior, etc.). As well, it is working one-on-one with the industrial (mining) sector on energy conservation/efficiency initiatives. In order for DSM to achieve the greatest potential it requires participation from all Yukoners.

2.0 20-Year Resource Plan Demand Forecasts

Yukon Energy is updating its 20-year resource plan which will address the corporation's generation and transmission priorities in Yukon to 2030. The plan will provide overall planning guidance for resource options to be implemented in the next five years and over the longer term. Energy conservation is an important part of the plan.

The hydro surplus in existence since the closure of the Faro mine in the late 1990s is becoming depleted as demand for electricity increases from all sectors (residential, commercial, government and industrial). Further, most of the hydro enhancement opportunities previously identified have now either been developed or are currently under active consideration. Yukon Energy is exploring a range of other energy options that will either minimize or displace reliance on diesel. Energy conservation/efficiencies is one of the best of these options, since the more electricity is saved, the less new infrastructure needs to be built.

[1] Yukon Electricity Conservation and Demand Management Potential Review (CPR 2011) released January 9, 2012

3.0 Public Response to Energy Conservation

Yukoners support energy conservation. A public opinion survey conducted for Yukon Energy in June 2010 reported 89 percent of Yukoners support assuming more personal responsibility toward energy conservation[2].

The energy charrette hosted by Yukon Energy in March 2011, which brought together about 100 Yukoners and energy experts from across Canada for three days to talk about the territory's energy issues, further confirmed support for DSM. Energy conservation was ranked as the most preferred energy resource option and was considered as a key resource planning option in the short, medium and long term planning scenarios (see Figure 2 below from the Charrette Report)

Figure 2: Energy Charrette March 2011

Summary of the type of choice cards selected per time frame scenario		
2015	**2025**	**2050**
• Hydro Enhancement (Marsh Lake) • Demand side management • Wind • Biomass • Hydro enhancement (Atlin Lake) • Hydro enhancement (Gladstone) • Liquefied natural gas • Solar • Waste to energy • Diesel enhancement • Individual district generation • On-site generation at large mines	• Solar • Wind • Liquefied natural gas • Biomass • Demand side Management • Medium sized hydro • Geothermal • Micro-nuclear • Small hydro/hydro enhancements • Vehicle battery storage • Waste-to-energy • Connection to B.C. grid • Independent Power Producers • Large hydro • Spinning reserve	• Solar • New hydro • Biomass • Demand side management • Grid connection with BC/Alaska • Liquefied natural gas (from pipeline) • Electric transportation • Geothermal • Micro-nuclear • New technologies

4.0 What Yukon Energy is Doing

Building on the public affirmation that DSM is a crucial element in helping us meet Yukon's growing electricity needs, Yukon Energy has moved forward on energy conservation. In working towards the development of a territory-wide energy conservation/efficiency plan, Yukon Energy has been involved in the following initiatives over the past year:

[2] Public and Stakeholder Phone Survey Results Public Awareness Campaign Phase 1: Research Report 1 released June 25, 2010

New Department

Yukon Energy established an energy conservation department in 2011 to work with stakeholders on Yukon-wide energy conservation and efficiency programs. This department will also help the Corporation find ways of reducing our own energy use. Energy conservation is a critical element in helping us meet Yukon's growing energy needs.

Working Group

Yukon Energy chairs an energy conservation working group, made up of representatives from Yukon Electrical Company Limited and the Yukon government's Energy Solutions Centre along with two of our own staff. We also participate in a Demand Side Management steering committee, made up of senior officials from the two utilities and the Yukon government. Both groups meet regularly to ensure planning is done collaboratively and that programs are executed in a transparent and cooperative manner that avoids duplication.

Conservation Potential Review

Yukon Energy has been working to find out more about how people use electricity in the territory and where the greatest gains might be in terms of energy conservation and efficiencies. In 2011 we partnered with the Yukon Electrical Company Limited and the Yukon government's Department of Energy, Mines & Resources to collect this information.

We hired ICF Marbek to do a conservation potential review. Through its research, the company sought answers to the following questions:

- How do Yukoners currently use energy (i.e. what percentage of energy consumption goes towards heat, hot water, lighting, plug loads, etc.)?
- How much power would Yukon need in future years if there weren't any energy conservation/efficiency initiatives put in place?
- How much potential is there in Yukon for energy savings through conservation/efficiency initiatives?
- Where are the greatest gains to be made in terms of conservation of electricity?

The consultants gathered the information using customer billing data, stakeholder consultation and customer surveys. They processed all the collected data and returned to Yukon in November to share their initial findings. Through stakeholder "Achievable Potential" workshops they asked participants to talk about how much of the electricity savings identified in the draft report can realistically be achieved within Yukon's residential, commercial and renewable sectors.

Marbek used the feedback it received during these workshops to further refine its report. The final report is now available to the public.

One Change Community Tour

In the summer of 2011 Yukon Energy took our conservation message on the road. Together with Yukon Electrical Company Limited and the non-profit group One Change, we visited almost every community in the territory. We set up tents with interactive displays in highly visible areas, gave away energy efficient products, and talked to hundreds of Yukoners about what they think a territory-wide electricity conservation plan should look like. The input will assist us in our work to develop conservation programs for Yukon.

LED Streetlight Pilot Project

In 2011 we did research on Light Emitting Diode (LED) streetlights in Dawson City, with positive results. The research shows that the annual energy used by the traditional High Pressure Sodium streetlights is 416 kilowatt hours per light, compared with only 150 kilowatt hours per LED streetlight, a savings of 64 percent.

However LED technology is changing rapidly and we would like to test some options that weren't available to us when we started the pilot project. This year we will experiment with several different types of LED streetlights before deciding which types/brands will be the best for our Northern needs.

Alexco Mine Audit

In the summer of 2011 we partnered with Alexco Resource Corporation to do an audit of their mine site near Keno. We'll continue working with Alexco this year to implement some of the suggested energy saving measures. We will conduct similar initiatives with other Yukon mines and we will work with the City of Whitehorse to audit their facilities.

Internal Audit

Yukon Energy is also looking at our own operations as well with an eye to conserving energy. In 2011 we completed an audit of our Whitehorse and Dawson City office and plant buildings and we are prioritizing actions that will increase the efficiency of our facilities. Yukoners will be able to follow our progress on our website (www.yukonenergy.ca).

City of Whitehorse Audit

Yukon Energy has partnered with the City of Whitehorse to do an audit in 2012. This pilot includes a look at continuous improvement as part of the audit/planning cycles.

Fridge and Freezer Retirement Program

In 2011 Yukon Energy partnered with the Yukon government's Energy Solutions Centre to help members of the public replace their old refrigerators and freezers with new more energy-efficient models. The used appliances must be at least five years old and in working condition. Not only will Yukoners received $50 for each fridge or freezer they have replaced (up to two appliances) but the Energy Solutions Centre will remove the old model, take it to the landfill, and pay the landfill tipping fee. Yukon Energy will continue to support this program this year.

Online Energy Calculator

With assistance from Maritime Electric, we developed an online energy calculator in 2011. It allows Yukoners to determine how much electricity each of their household appliances and other electronic equipment requires to operate. The tool gives members of the public the ability to better manage their electricity usage and lower their power bills.

Tradeshows

In the spring of 2011, Yukon Energy ran a public awareness campaign that promoted the use of clotheslines. Employees set up a booth at an annual trade show in Whitehorse and gave away hundreds of packages of clothespins, along with several drying racks and clotheslines. We also provided tip sheets that included other energy saving information.

This year we will once again be set up at the Lion's Trade Show in Whitehorse with a very large Plinko game board. People will have a chance to play Plinko to win energy-savings products. We'll also have our Plinko board set up at Swan Haven on April 21 and 22 during Celebration of the Swans.

Dollars to Sense Workshops

Yukon Energy, working with Yukon Electrical Company Ltd., and Natural Resources Canada, hosted a series of energy management workshops in 2011 for Yukon businesses and First Nation and municipal governments. Sessions were offered both in the spring and fall. We will offer them again in future years if there is demand.

Energy Conservation Kids Ed-Venture Program

Yukon Energy and the Yukon Conservation Society partnered in 2011 to provide an afternoon of learning and fun for pre-schoolers, focused on energy conservation and electricity. The aim was to teach the children about using electricity safely and wisely. This was done through music and dance, storytelling, hands-on science and crafts. We plan to expand this program to other locations this summer.

Earth Hour

Yukon Energy worked with the Yukon Conservation Society and the Yukon government's Energy Solutions Centre both last year and this year to promote Earth Hour. It's an annual event that encourages people to reduce their energy consumption as much as possible for one hour, and think of ways that they could continue to conserve throughout the year. This year Yukoners reduced their energy consumption by about 1.1 megawatts. That's up from 2011, at which time Yukoners cut their consumption by 1 megawatt. In 2010 reduced their electricity usage during Earth Hour by .8 of a megawatt.

5.0 Conclusion

Yukon Energy is committed to working with Yukoners to develop a strong and effective energy conservation plan for the territory.

Over the last year the corporation and its partners have devoted a great deal of time and effort to building a framework for such a plan. However there is more work ahead, and your thoughts and suggestions are a crucial part of the planning process. Thank you for your time and support for a clean energy future.

Demand Side Management for the Yukon

- Initial stakeholder consultation (January 2011)
- Conservation Potential Review
- Program Design Development
- Market Characterization
- DSM Plan
- Implementation Plan
- Evaluation, Measurement and Verification Plan
- YUB Approval

Utilities DSM Process

- Total electricity consumption in 2010 - 312,000 MWh/yr
- By 2030 expected to rise to 515,000 MWh/yr, an increase of about 65%
- DSM measures could provide between 66,000 and 97,000 MWh/yr of savings by 2030

CPR Results

- The proposed programs focus on saving electricity
- The DSM Plan recognizes the importance of working with not for profits, community groups and government departments to deliver successful programs
- Jointly, the Utilities commit to an annual electricity conservation target of 8.5 GW/h of sustained savings by year five.

Scope

- The Utilities commit to work together to deliver the programs to all our customers
- Yukon Electrical will lead in the area of outreach and delivery of programs to customers
- Yukon Energy will provide technical expertise and lead in the overall accountability and reporting

Utilities Commitments

- Two scenarios – with and without government buildings
- The program portfolio projects 98.9 GW/h of measure-lifetime net savings.
- General Service programs including government buildings will generate 67% of the measure-lifetime net savings.
- Residential programs including government buildings will generate 33% of the measure-lifetime net savings

Savings Highlights

- Designing programs for the Yukon context
- Less than the Cost of Conserved Energy
- Passing the Cost Effectiveness Tests
- Identifying the program priority opportunities

Program Development

Test	Key Question Answered
Participant Cost Test	Will the participant benefit over the measure life?
Program Administrator Cost Test	How much will the DSM program administrator pay for savings?
Ratepayer Impact Measure	Will utility rates increase?
Total Resource Cost Test	Will the total costs of electricity in the utility service territory decrease?

Cost Effectiveness Tests

Residential Programs

- **LED Lighting & Automotive Heater Timer Rebates**
  - A flat rebate will be provided after the purchase of a lamp or fixture from a prescribed list of eligible products.
  - A flat rebate will be provided after the purchase of a block heater timer, car warmer and/or a battery blanket from an eligible product list.
  - 5 year total cost - $604,000 ($217,000 incentives)

- **Low-cost Energy Efficient Products**
  - The utilities will provide information to customers on certain low-cost items through retail outlets.
  - These include: low-flow showerheads, faucet aerators, DHW tank insulation, smart power bars, etc.
  - A limited number will be provided to customers free of charge and ask for feedback from those customers.
  - 5 year total cost - $1,033,000 ($192,000 incentives)

Residential Programs

Residential Programs

- **CCHP and GSHP Initiative**
  - A pilot program to test three-element hot water heaters, cold climate heat pumps and ground source heat pumps.
  - The technology will be subsidized, not provided free of charge and results will be provided.
  - This program will be available to new construction and retrofit homes
  - 5 year total cost - $209,000 ($65,000 incentives)

- **Public Engagement, Education and Communication**
  - Information will be provided to customers through the following channels:
    - Engagement with the retail sector
    - Point of purchase displays and brochures
    - Partnerships with non-profit and community agencies
    - Outreach and participation in community events
    - Identification of electricity efficiency partners
    - Efficiency workshops
    - Direct engagement with contractors
    - Advertisement
    - Website
  - 5 year total cost - $657,000

Residential Programs

- **Lighting Redesign and Equipment Incentive**
  - An incentive will be paid to have building lighting systems redesigned.
  - The custom incentive includes a base incentive for equipment and installation using a dollar per kilowatt hour annual savings rate.
  - An additional incentive is provided for choosing LED products
  - 5 year total cost - $1,487,000 ($1,062,000 incentive)

General Service Programs

- **High Efficiency Refrigeration Incentive**
  - An incentive will be paid to have refrigeration systems retrofitted.
  - This will be a custom incentive using a per kilowatt hour rate for each kilowatt hour saved.
  - Extensive refrigeration-specific technical assistance will be provided to assist in identifying the opportunities
  - This program is aimed at hockey, curling rinks and grocery stores.
  - 5 year total cost - $553,000 ($263,000)

General Service Programs

- **ENERGY STAR Computer Incentives**
  - An incentive will be paid to Yukon-based companies or organizations that purchase computer equipment that meets ENERGY STAR requirements.
  - The incentive will be a fixed amount per piece of equipment.
  - 5 year total cost - $284,000 ($98,000)

General Service Programs

- **New Construction Incentive**
  - An incentive will be paid for high performance new buildings.
  - The program will have two paths: a prescriptive path for small buildings and a custom path for large buildings.
  - The prescriptive incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard
  - The custom incentive will be determined using a dollar per kilowatt-hour of annual savings
  - 5 year total cost - $208,000 ($115,000 incentive)

General Service Programs

- **Engagement, Training and Communication**

  - Information will be provided to customers through the following channels:
    - Direct Engagement with building actors (electrical distributors, lighting designers, electrical contractors, etc)
    - Hands-on, in-person courses for local building actors
    - Project-specific lighting design or advanced HVAC design technical support
    - Trade events and gathering local building owners/managers and building actors
    - Support for building owners/managers to do asset management planning, optimizing decisions about implementation and procurement, tendering of project design service, etc.
  - 5 year total cost - $1,199,000

General Service Programs

- Public face of the Utilities for delivery of the programs
- To provide a one stop brand for customers to search, talk to and engage with
- Lessens Yukon Energy/Yukon Electrical confusion.

inCharge Brand

Costs

	Annual Cost	Annual Savings
Year 1	$824,000	240 MWh
Year 2	$1,240,000	1487 MWh
Year 3	$1,393,000	4318 MWh
Year 4	$1,266,000	6451 MWh
Year 5	$1,480,000	9250 MWh
Total	$6,203,000	

These costs are split 50/50 between Yukon Energy and Yukon Electrical

- Mechanism to report, evaluate and verify savings realized versus forecast savings
- Verify performance of programs and provide recommendation for improvements
- Provide a framework of accountability
- Completed by a certified third-party evaluator

Evaluation, Measurement & Verification (E,M & V)

- CPR, DSM Plan and supporting documents submitted as part of Yukon Electrical GRA
- Deliver Implementation Plan and EM&V Plan to the YUB - July 2013
- GRA decision expected by first quarter 2014

Next Steps

Yukon Energy Corporation and

The Yukon Electrical Company Limited

Demand Side Management Plan

January 13, 2011 Focus Group Session

Synthesis Report

Prepared by Paul Kishchuk, MA
Vector Research

February 28, 2011

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Introduction

The Yukon Energy Corporation and The Yukon Electrical Company Limited were directed by the Yukon Utilities Board in 2009 to jointly develop a Demand Side Management (DSM) Plan. Development of the DSM Plan is to involve intervenors, communities and stakeholders. The completed DSM Plan will be reviewed by the Yukon Utilities Board.

Both the Yukon Energy Corporation and The Yukon Electrical Company Limited also recognize that electricity use in Yukon is increasing each year. By influencing consumer behavior through the delivery of incentives/disincentives for using electricity at certain times or for certain purposes it is hoped that that need for electricity from new generation sources can be reduced and/or delayed.

The DSM Plan will also be developed within the context of the Yukon Government's *Energy Strategy for Yukon* which calls for the development of a demand management program. The Yukon Energy Corporation and The Yukon Electrical Company Limited are working with the Yukon government to ensure consistency with current DSM initiatives.

On January 13, 2011 the Yukon Energy Corporation and The Yukon Electrical Company Limited initiated public participation in the development of the DSM Plan by hosting a focus group session with an invited group of participants. A total of 15 participants, representing a broad selection of stakeholder and community agencies, attended the January 13 session. The individual participants and the organizations they represented are listed below in alphabetical order:

Shane Andre – YG Energy Solutions Centre
Shannon Clohosey – City of Whitehorse
Marianne Gregoire – YG Highways & Public Works
Lawrence Ignace – Indian and Northern Affairs Canada (Yukon Region)
Rick Karp – Whitehorse Chamber of Commerce
Juergen Korn – YG Yukon Housing Corporation
Laurie MacFeeters – Yukon Anti-poverty Coalition
John Maissan – Leading Edge Projects Inc.
Anne Middler – Yukon Conservation Society
Steve Mooney – Yukon Cold Climate Innovation Centre
Manon Moreau – YG Energy Mines and Resources (Energy Strategy)
John Pattimore – Association of Yukon Communities
Roger Rondeau – Utilities Consumer Group
Mike Wark – Yukon Chamber of Mines
Rebecca World – YG Climate Change Secretariat

A representative from both the Yukon Energy Corporation and The Yukon Electrical Company Limited were also present at the session to assist with technical questions:

Hector Campbell – Yukon Energy
Christopher Cullingham – The Yukon Electrical Company Limited

The facilitators for the focus group session were:

Paul Kishchuk – Vector Research
John Streicker – Professional Engineer

Notes were taken at the focus group session by Ramona Toth.

As the focus group session was the launch for public participation in the development of the DSM Plan, Mssrs. David Morrison and Dwight Redden made brief opening comments on the context for the DSM work being undertaken by both utilities before taking their leave from the session. David Morrison is the President and CEO for Yukon Energy Corporation and Dwight Redden is the General Manager for The Yukon Electrical Company Limited.

The stated purposes of the half-day session were to:

1) identify key demand side management issues from the perspective of the agencies and organization represented at the session; and,
2) seek direction on how to best involve agencies and organizations present at the session in the development of a demand side management program.

The focus group session commenced at 9:05 a.m. and wrapped up at 12:00 noon.

The focus group session was carried out in accordance with the Chatham House Rule. Participants were advised that they could, subsequent to the session, talk about what they had heard and learned at the session but that they were not at liberty to do so in a way that would reveal the identity of an individual or organization. In fulfillment of the Chatham House Rule commitment made at the focus group session, no statements, remarks or suggestions are attributed to specific individuals or organizations in this report.

As the responses to each of the questions outlined below are presented in no particular order, no meaning should be attached to the order in which a response appears within a list.

Why is your organization interested in energy issues?

- Because we are working to implement government policies (Energy Strategy, Climate Change Strategy) or programs (homeowners, energy efficiency programs, infrastructure, Cold Climate Innovation);
- We represent businesses and industry who as large electrical energy consumers are correspondingly exposed to cost increases;
- We represent people and organizations concerned about CO_2 emissions, environmental impacts, energy efficiency (conservation), electric bill costs, energy security; and,
- We represent people and organizations hoping to educate and create a culture of electrical energy conservation among people and within organizations.

What are some examples of Demand Side Management programs and initiatives?

- The encouragement of a "conservation culture" where behaviors are shifted and knowledge encouraged so that people are aware of their individual consumption impacts;
- Programs delivered by B.C. Hydro for low income individuals/renters;
- Consumer awareness tools such as pie charts for electricity rates at certain times of the day;
- Education about how to conserve electricity so that everyone can make changes;
- Energy conservation or efficiency programs via the customer base such as energy rebates, load shifting or adding loads;
- Good "real time" information (e.g., graphs, billboards, turning off streetlights) to make it easier for people to visualize and comprehend limits and know when to shift loads;
- Hot water tank timers and low flow showerheads;
- Targeted education and implementation of programs for low income people and renters (could include modifications to rate structure) since there is no point in delivering programs to people who cannot take advantage of them;
- Transparent information for consumers so they can understand how the different rates, riders, rebates and taxes all fit together;
- DSM incentives for renters whose electrical bills are paid by their landlords;
- Energy efficient building design since good design is more economical than retrofitting;
- Electricity rate structures that discourage electricity consumption at times of hydro-electric under-supply and encourage electrical energy use at times of hydro-electric over-supply;

- Standards/regulations for all new buildings through revisions to building codes that incorporate energy efficiency;
- Strategic use of energy;
- Supply side management of electricity by the utilities (e.g., during peak morning an evening periods);
- Load shifting by mines so that consumption is reduced during times of peak consumption on the grid, perhaps through monetary disincentives tied to whether or not diesel-generated electricity could be avoided through reduced electricity consumption by industrial customers (it was pointed out that coordination of demand responses with large-scale customers is typically already being done by electricity suppliers);
- Better bill information so that consumers know when they've jumped to a higher rate block, similar to a telephone bill that shows the difference in cost if you made a call during a peak period versus a discount period versus a "deep" discount period, perhaps there could be an addendum to the bill explaining the details of how the bill was calculated;
- Consumer education (including units of measure and other basic electricity concepts) so that when consumers are reviewing their bills they understand how the bills were calculated;
- An understanding of the audience and client base needs to be developed to be able to properly target DSM information to different consumers;
- We should consider all potential DSM opportunities rather that focusing on savings in just one area of electricity consumption;
- Perhaps larger-scale consumers could sign some sort of risk/confidentiality waiver and work directly with the Energy Solutions Centre through the sharing of bill information; and,
- Government to government transfers could be tied to implementation of energy efficiency and conservation measures (parallel idea to sustainability plans and gas tax funding).

Are there any specific DSM initiatives not well suited to the Yukon?

- Adoption of time-of-use rates in the Yukon needs to be further explored including comparisons with other measures such as load shifting from day to night;
- If new supply cannot be avoided, it was pointed out that some other jurisdictions are reconsidering nuclear options, something which may not be acceptable to Yukoners;
- DSM initiatives that create consumption disincentives for mine operators need to recognize that electricity is an integral input to mining processes, mines exist to make money and reducing production reduces income. Unexpected shutdowns can affect workers pay. This is not to say that the mines and mine workers disagree with DSM, just needs to be done in a feasible way;
- The obligation to serve provision of the *Public Utilities Act* (i.e., if a mine builds a power line to the grid the utility must build capacity and supply electricity), which can adversely affect existing customers on the grid, should perhaps be revisited;
- If supply is to be scaled back at times of peak consumption, there needs to be a public discussion about how to choose who gets power first (i.e., whose electricity supply is reduced);
- DSM initiatives should be avoided that increase the use of diesel generation in or near communities where noise and air pollution are issues. Diesel generation may best be located next to the industrial users, like mining operations, where waste heat from the generators could economically be used to heat buildings;
- We should look at the larger consumption issue and not just savings in one area; and,
- DSM initiatives that result in less electric heating being available to residential customers and indirectly contribute to increased use of heating methods which diminish air quality (such as the burning of wood or oil to produce heat), should be discouraged.

If you could have your pick, which DSM program or initiative would be the first choice for your organization?

- A public education campaign to promote awareness of how to reduce electricity consumption [suggested by five participants];
- All new building construction built and maintained to be as energy efficient as possible.
- An on-going marketing campaign about electrical energy as no one understands it and doesn't worry about it until it's gone;
- Continued evolution of our electrical bills (monthly usage chart on current version of electrical bill is useful), however information needs to be at grade 7 level to ensure greatest number of consumers benefit from information availability;

- Design and implement tools/information for employees of large organizations (who now feel powerless to conserve energy in the workplace) to allow them to demonstrably conserve energy in the workplace;
- Design and implementation of an electricity rate structure that encourages DSM-like behaviors;
- DSM measures that have some sort of "price shock" aspect (e.g., like over-threshold internet access charges), can be effective as people will learn from it;
- Electrical energy guidelines, regulations and accessible information needs to be specific to each Yukon community as each community is different;
- Employees of large organizations are also electricity users at home so education efforts in the workplace can have indirect benefits in the residential sector;
- Energy audits in small communities to establish baselines for electricity conservation initiatives;
- It needs to be remembered that it is difficult to ask industrial users such as mines to shut down or scale down on short notice as it is akin to asking mine workers to give up their pay cheques, such shut/scale downs need to be properly planned out to minimize effects on mine operations (and it was noted that this type of planning is already done);
- Loan programs for upgrades whereby the savings are used to pay off the loan;
- Money is required for all DSM programs, since implementing DSM programs can be far cheaper than building new infrastructure or waiting for existing infrastructure to wear out;
- Programs that result in implementation of DSM programs are required;
- Regulations to encourage energy conservation (such as improved building codes), while likely the most tricky to implement, will be the most valuable/effective;
- Smart metering for households (including smart hot water heaters);
- The electrical utilities should network with consumers and businesses to transfer information about the benefits of electrical energy conservation, people need to be able to see the "light at the end of the tunnel" if they are to adopt new consumption habits that will stay with them;
- The greatest conservation successes will come from more energy efficient building design and construction rather than from retrofitting existing buildings;
- Thorough follow-up and assistance with DSM initiatives and programs to ensure effective implementation and actual savings – for example, it's not good enough to hand out low-flow showerheads if people don't know how to install them and they end up sitting on a shelf;
- Transparent linkages between electricity-conserving behaviour and cost savings; and,
- Whatever programs are chosen to implement, the potential for savings exist right know, let's get them implemented ASAP!

What are the perceived barriers to the uptake of DSM programs that come to mind?

- Conservation is a lifestyle change that people need to make and if people are to change they must perceive that it is somehow "worth it";
- Finding funding for DSM programs will be a barrier, the funding has to come from either electricity rates or taxes;
- Good program design requires the collection of accurate statistics on the number of people on electric heat as well as the number of people living in houses that that need retrofitting;
- If minimum specifications are regulated (i.e., building codes) retrofitting will become even more costly in the future; we already have an affordable housing problem so if building codes are changed to increase minimum standards, housing will become even less affordable, this also needs to be addressed; it was pointed out that the payback on more efficient building construction is immediate, a person will pay less in energy costs than they will in the incremental increase in mortgage costs (in other words the savings in operational costs more than offset the increase in capital costs);
- Incentive-type programs/initiatives are not always worth it in terms of conservation results;
- People are generally willing to pay more for something that brings convenience, problem with electricity is that it costs the same whether used for a basic need (e.g., hot water) or a convenience (e.g., hair drier);
- Reductions in consumption will reduce revenues for the utilities so in times of surplus electrical energy the utilities will be less vigilant about conservation, as a result need to think about how to ensure energy conservation is "always in fashion" for the utilities and consumers alike;
- Retrofitting is expensive and may not be feasible for everyone;
- Strong leadership from YEC and YECL and YG is required. "If you build it, hopefully people will follow";
- The capacity of people to adopt changes needs to be considered in the design of DSM programs. For example, someone working 3 jobs will not likely have the energy/time to make good conservation choices;
- The greatest challenge is getting buy in from the public to conserve energy;
- There are currently no incentives for renters to conserve electricity; and,
- There is always a fear of change and that people may feel that they don't need education so there could be public resistance if there is not proper information.

Who should pay for the design and implementation of DSM programs and initiatives?

- Both ratepayers and taxpayers have a duty to pay (and likely both will pay);
- DSM initiatives likely cannot offset all the need for new generation, rates will go up as new generation is built, public may perceive that DSM is wasted effort since rates are going up anyways, how to convince people that rates will go up less if they conserve electrical energy?;
- Educating taxpayers is the same thing as getting government to pay;
- Government is already contributing because of the cross subsidy from government to residential customers;
- Remember that conservation programs aren't all about costs since reducing consumption results in saving for consumers; and,
- The bill subsidies now in place should continue to be in place until DSM programs/initiatives are implemented and education activities are in progress.

How should it be decided which agency or organization will be the lead on a particular program or initiative?

- Both utilities (YEC & YECL) should make the case for DSM to the public and then agencies and organizations should make contributions as appropriate;
- Collaboration is important but one entity needs to "take the reins" and lead and also facilitate partnerships;
- Let's get going on a Public Awareness Campaign!;
- Partnerships are key;
- Terms of Reference to the Yukon Utilities Board could be a starting point;
- The Department of Education should be involved so that young people can be involved and perhaps will come home and help educate parents;
- The Yukon Government and the electrical utilities have concurrent responsibility for DSM; and,
- Ultimately it will be the government's lead, as they will direct the utilities that they implement DSM programming (it was pointed out that utilities are already on board);

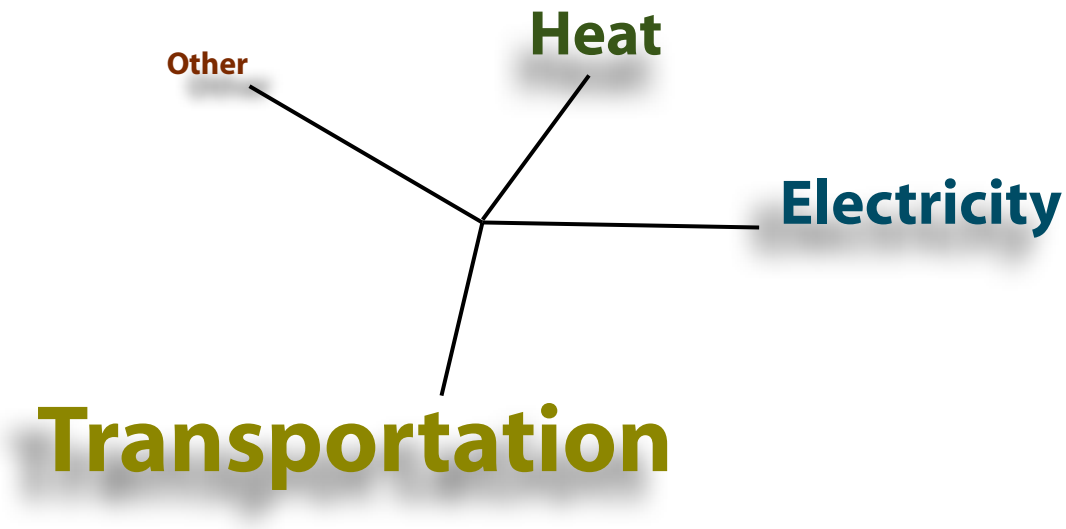
Going forward, what form of engagement would you like to see? Should other business/organizations be involved?

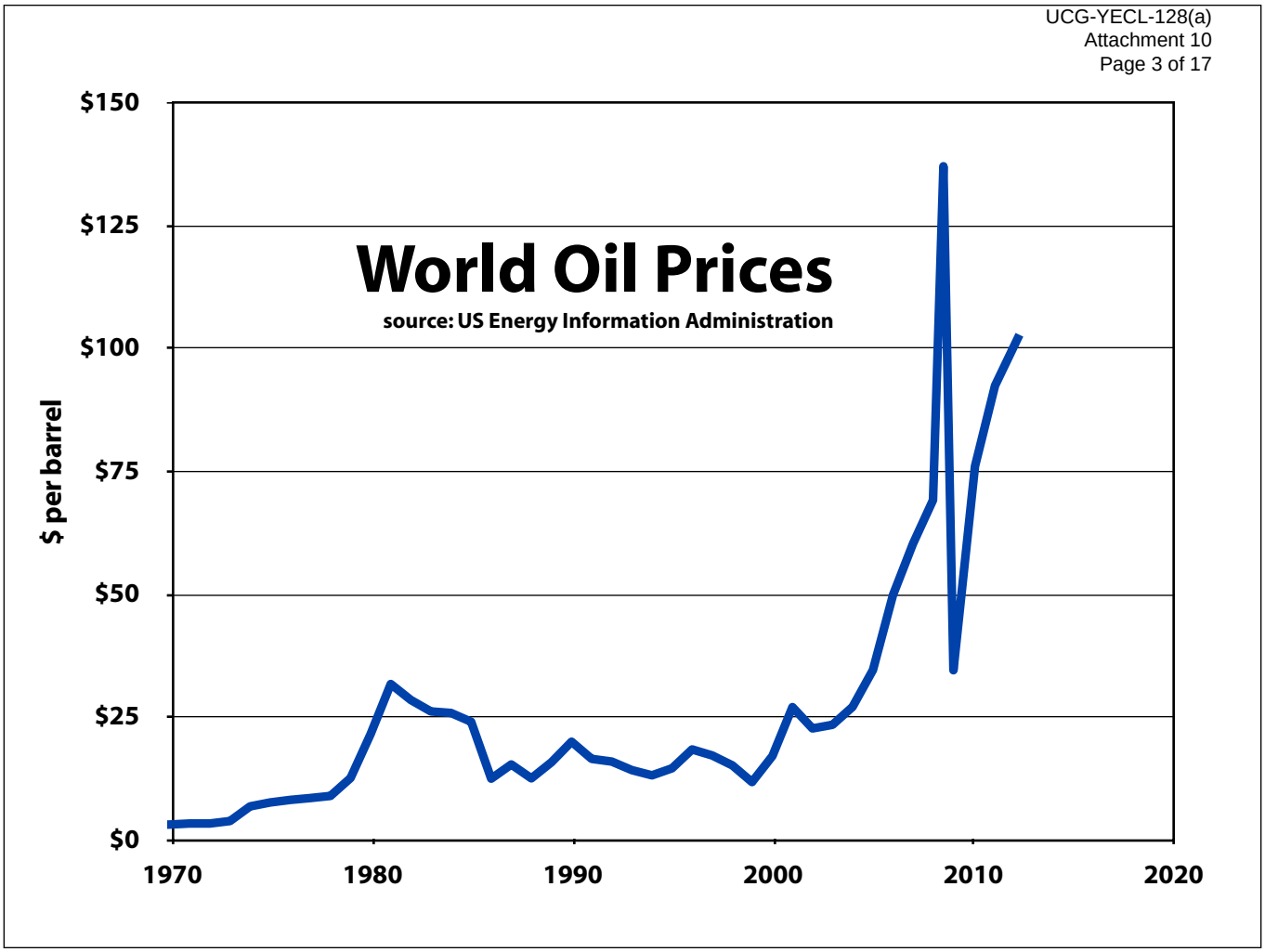
- Among participants there was general agreement that the focus group session was a good start and that the organizations they represent would be glad to continue to participate and help in any way they can, including communicating with the members of their organizations;
- An organization represented at the focus group noted they have networking as part of their mandate and would be happy to facilitate further discussion on the topic of DSM;
- Continued facilitated discussions like this one, having a variety of stakeholders to work with is essential;
- Consumers should be encouraged to contribute ideas and engage and participate in DSM planning;
- Continuing to work in a forum similar to today's focus group would be beneficial;
- Create a "DSM website" hosted by the utilities that can be a repository for DSM information for this working group as we move forward;
- Create an email list for the focus group participants as a way of staying in communication;
- Develop strategies to get input from the public;
- Empower grassroots individuals and organizations sooner rather than later and keep them informed;
- Partnerships between the utilities and other agencies and organizations;
- Real timelines need to be set and communicated, organizations need to be kept informed;
- The utilities need to have direct contact with the business community to discuss DSM initiatives;
- The utilities should take ownership of the issue at the start and then utilize other groups to move forward;
- There should be direct discussions between the utilities and industrial consumers (i.e., mines); and,
- Utility-led group discussions on DSM within organizations represented at the focus group.

Why DSM?

Sustainability for the Yukon

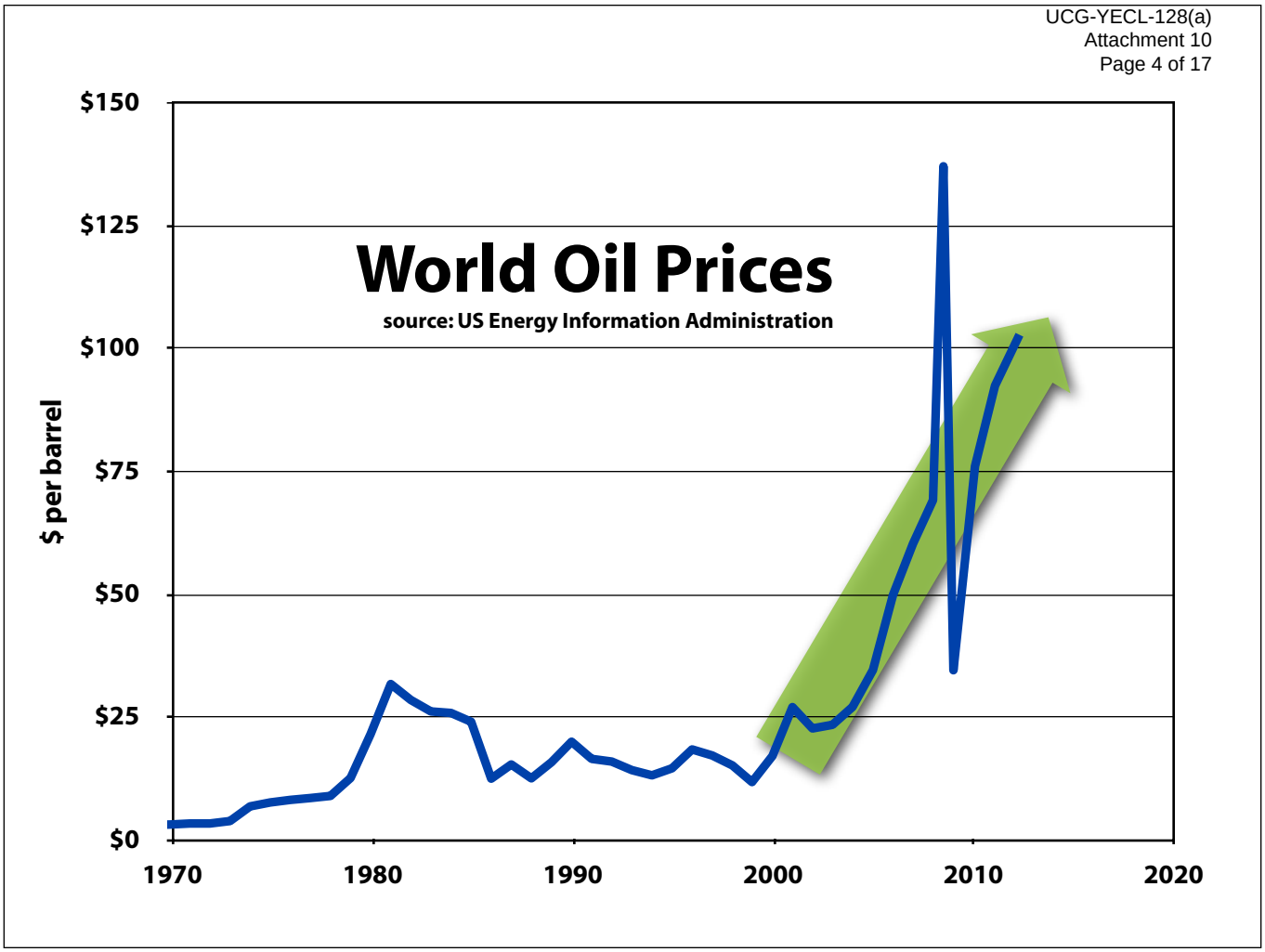
Yukon Energy





Data Source: US Energy Information Administration

Graph Source: John Streicker

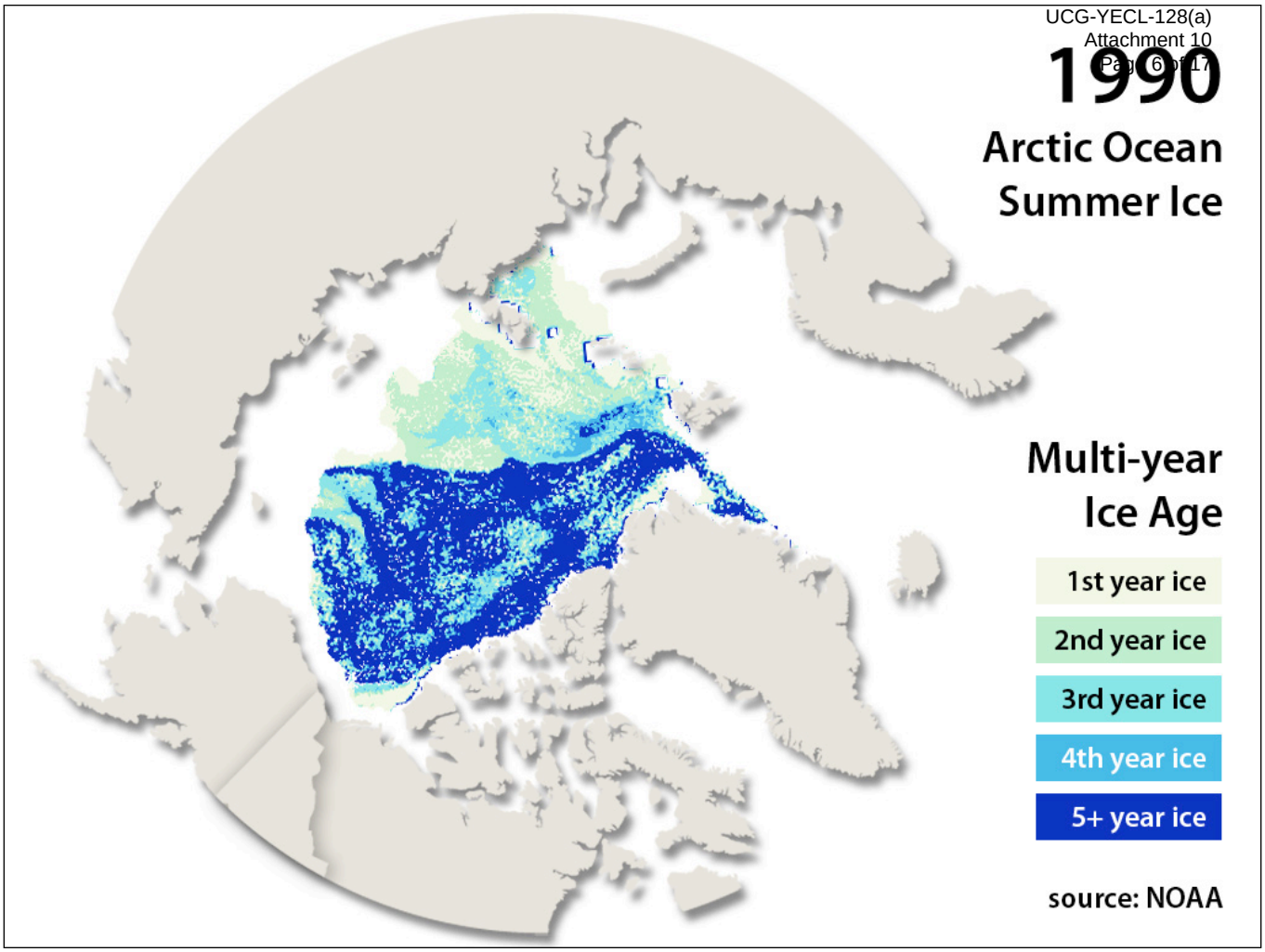


Data Source: US Energy Information Administration

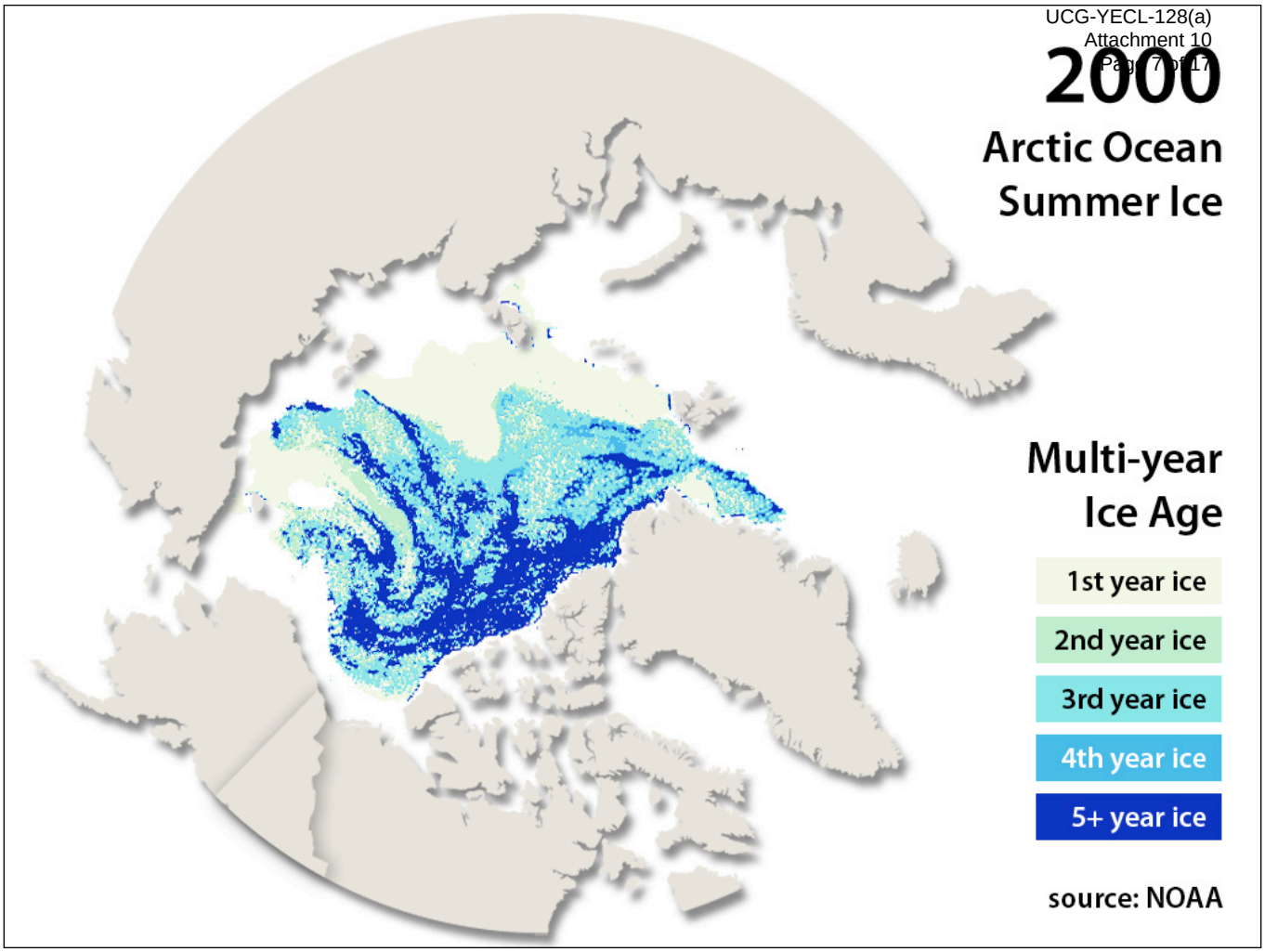
Graph Source: John Streicker



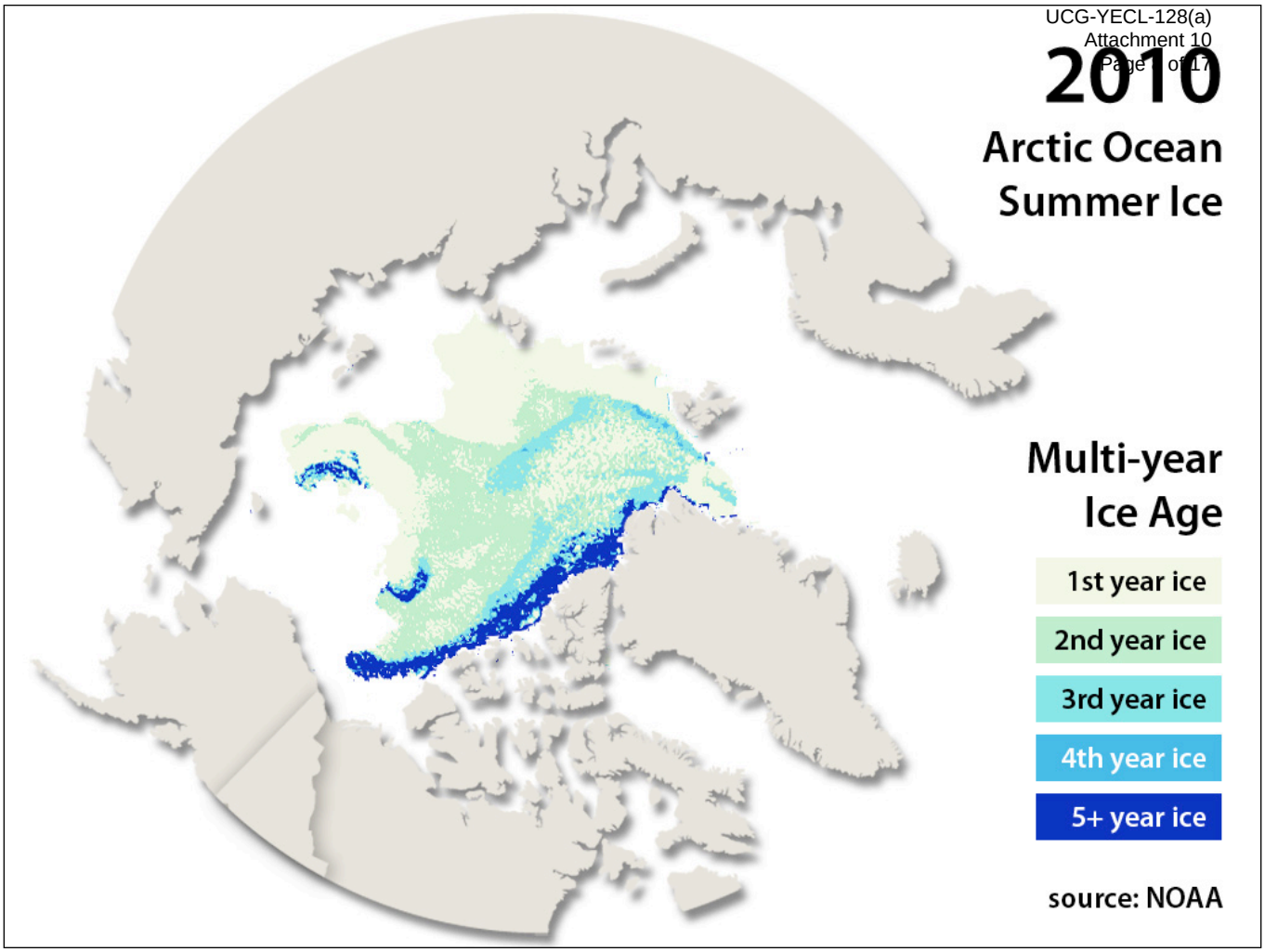
Consumption



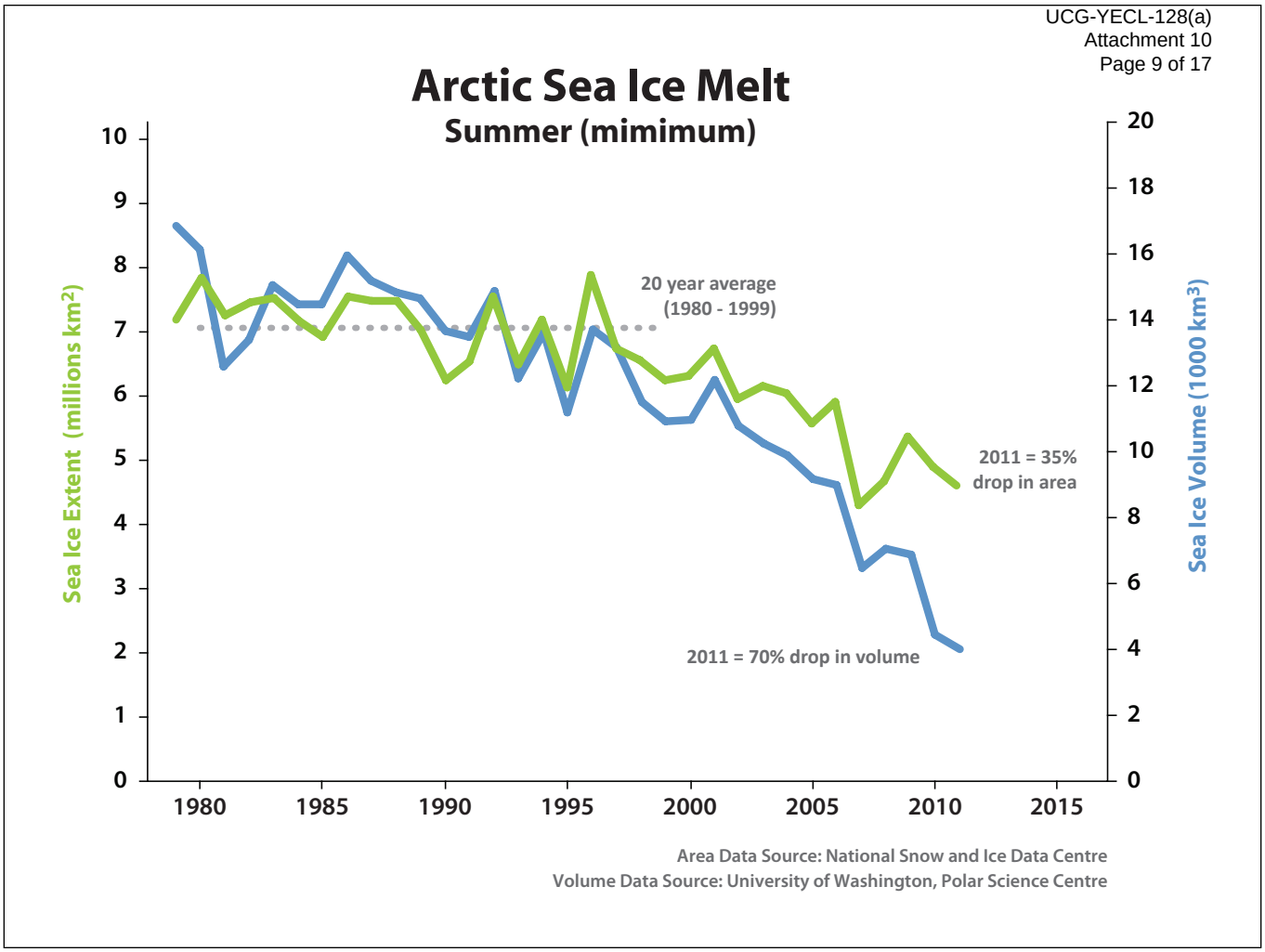
Data Source: National Oceanic and Atmospheric Administration (NOAA) with data from James Maslanik, University of Colorado
Image Source: John Streicker



Data Source: National Oceanic and Atmospheric Administration (NOAA) with data from James Maslanik, University of Colorado
Image Source: John Streicker



Data Source: National Oceanic and Atmospheric Administration (NOAA) with data from James Maslanik, University of Colorado
Image Source: John Streicker

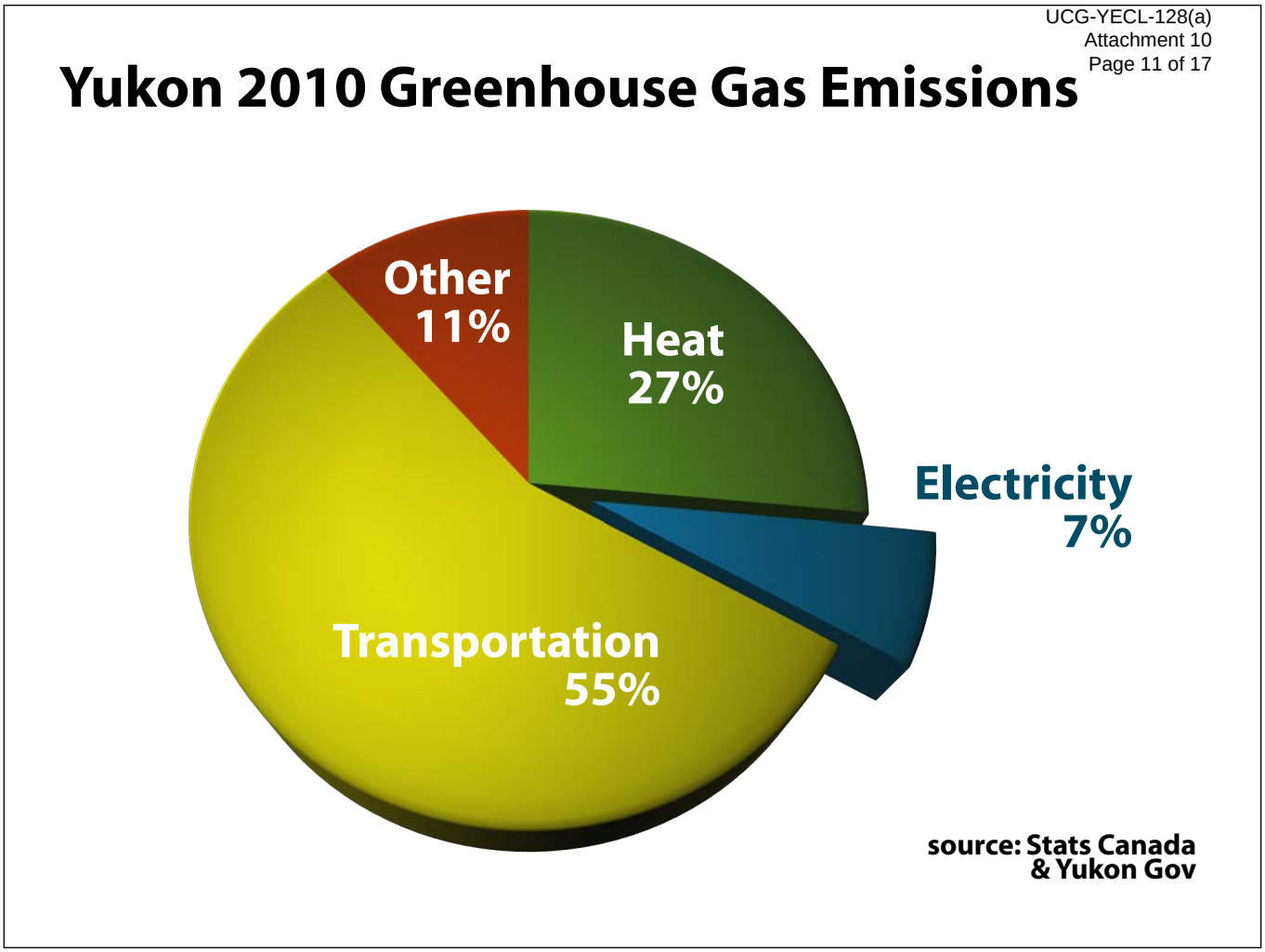


Data Source: National Snow and Ice Data Centre (NSIDC) and Polar Science Centre at University of Washington
Graph Source: John Streicker

“If we don’t change our energy system in a radical way in the next ten years, the wheels will come off.”

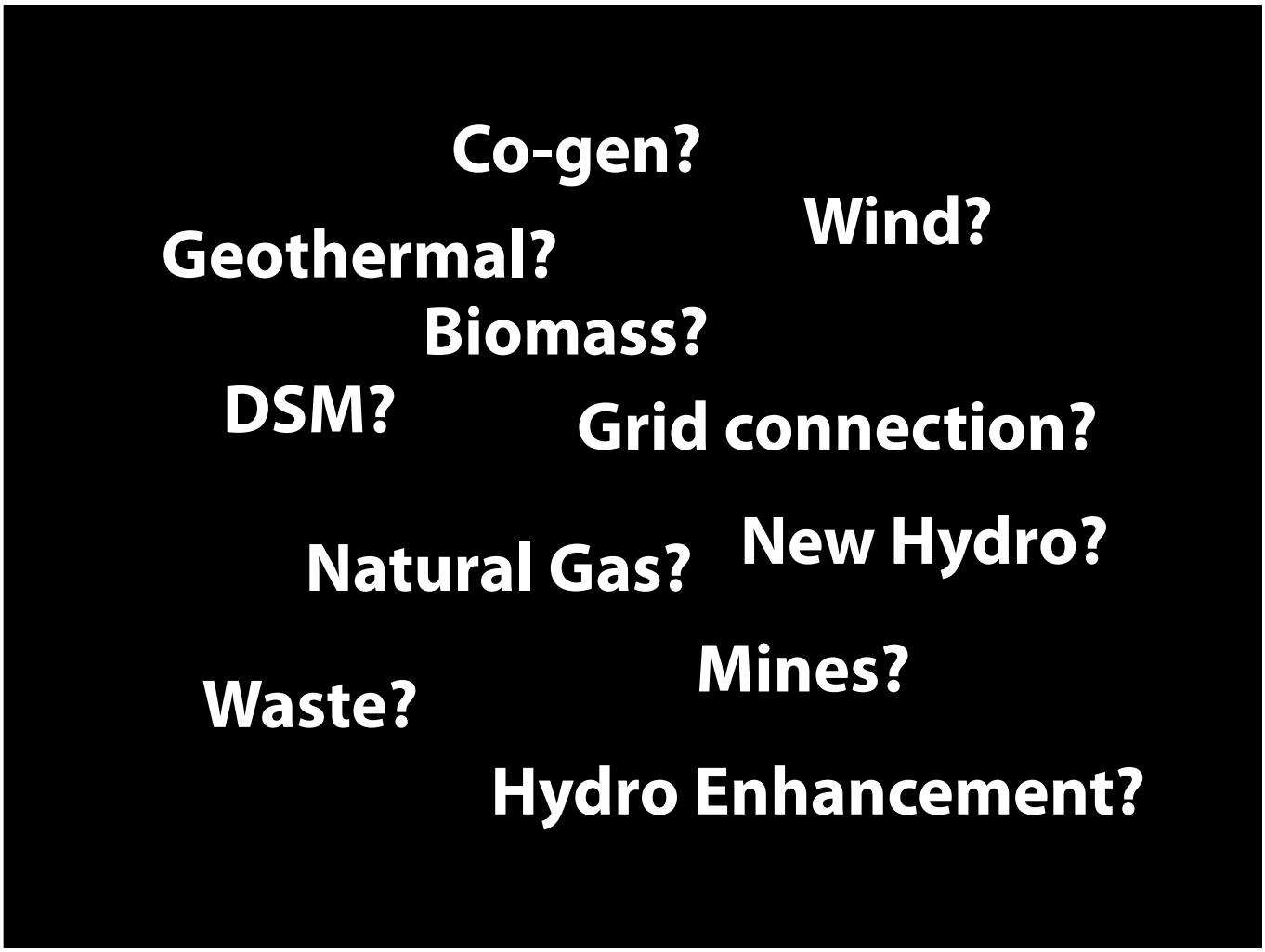
- Fatih Birol, Chief Economist, IEA, 2007

Notes:Quote is from press release around the International Energy Agency’s World Energy Outlook, 2007



Data Source: Statistics Canada and Yukon Government Climate Change Secretariat

Graph Source: John Streicker


Co-gen?
Wind?
Geothermal?
Biomass?
DSM?
Grid connection?
New Hydro?
Natural Gas?
Mines?
Waste?
Hydro Enhancement?

1. reliability
2. affordability
3. flexibility
4. environmental responsibility

#1 - conservation

#2 - efficiency

at the consumer level

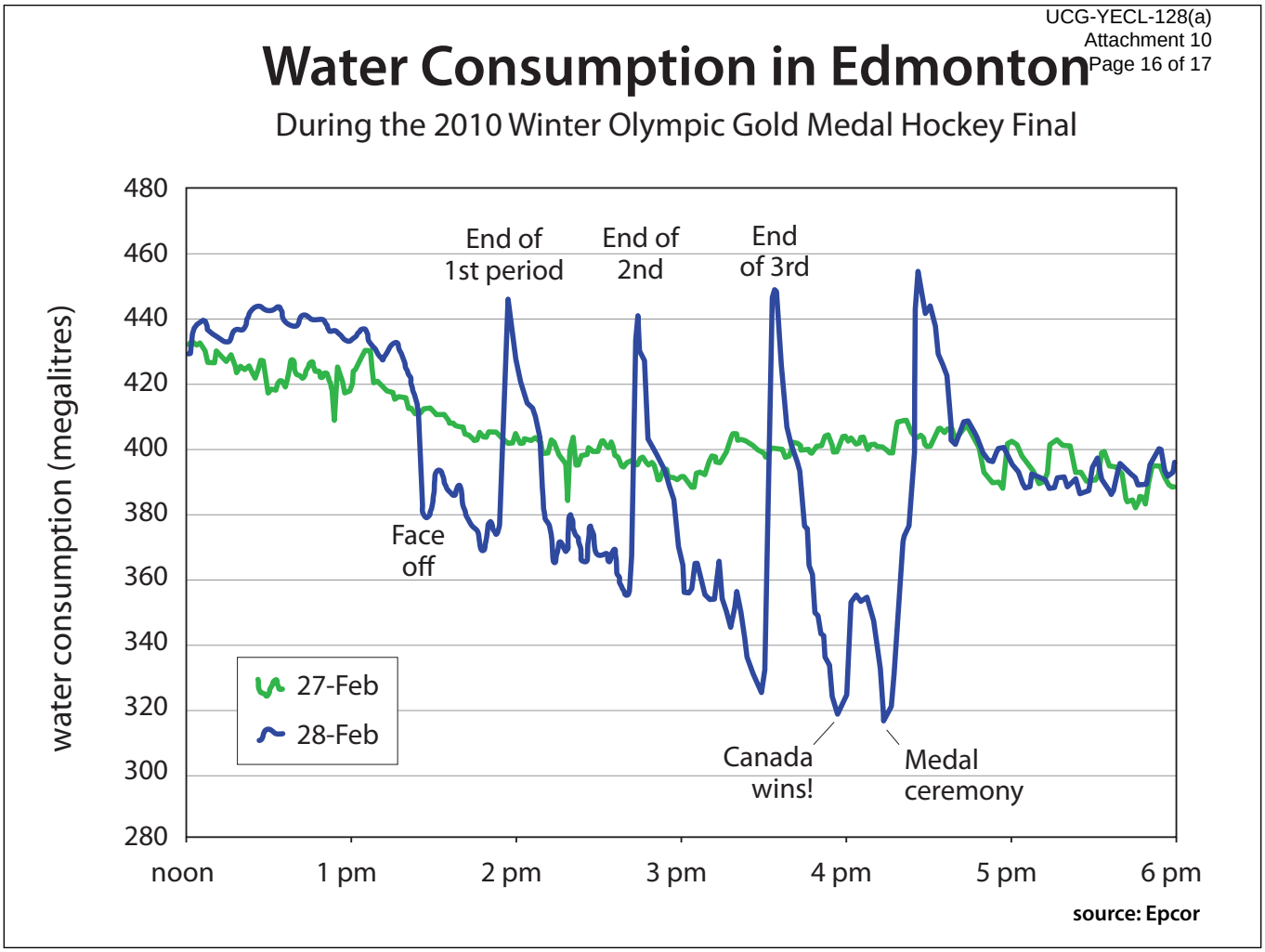
conservation

+ efficiency

= DSM



Behaviour



Notes:

1. The 2010 Olympic Men's Hockey gold medal final match on Sunday 28-Feb was a great example where a behavioural change could happen
2. Edmonton monitors its water usage at all times
3. Someone noticed that the water usage on 28-Feb was very different from the day before, Saturday 27-Feb
4. It is very easy to see the signature of the hockey game on the water usage chart, including the three periods, the overtime and even the medal ceremony
5. During the game, water consumption dropped by 5%
6. All it took was people flushing between periods

Data Source: EPCOR

Graph Source: John Streicker



Big Picture

Photo Source: John Streicker

Yukon Electrical – One Change – YEC Tour

Summary

Yukon Electrical and Yukon Energy have engaged the One Change Foundation to conduct a tour across the Yukon to stimulate conversations among community leaders and the general population that will assist in guiding the utilities towards a territory-wide energy conservation policy.

Staff Assignments

Team #1	Team #2
Deb Gleason-One Change	Stuart Hickox (plus 1)-One Change
Allison Fitzgerald -One Change	Christine (plus 1)-One Change

Event Dates

Old Crow	June 23	Team #2 – Dwight, Wendy & Jay
Faro	June 24	Team #1 – Laura
Dawson City	June 25	Team #2 – Wendy
Ross River	June 25	Team #1 - Laura
Pelly Crossing	June 26	Team #1 – Laura
Carmacks	June 27	Team #1 – Laura & Wayne
Teslin	June 27	Team #2 – Wendy & Jay
Whitehorse	June 28	Team #1 – Wayne & Laura (Laura at public meeting)
Watson Lake	June 28/29	Team #2 - Wendy & Jay
Burwash Landing	June 29	Team #1 – Laura & Wayne
Haines Junction	June 29/30	Team #1 – Laura & Wayne
Whitehorse	July 1	Team #1 & #2 – Laura & Wendy

Pre-tour Timeline

Wednesday, June 15			
	Klondike Sun Ad		¼ page ad to run
	Yukon News Ad		¼ page ad to run
	Confirm arrangements for Birthday Cake, food and beverages		Wendy
	Tents arrive Whitehorse		YECL Office
Friday,			

June 17			
	Yukon News Ad		¼ page ad to run
Monday, June 20			
	Prep YECL packages		Laura & Wendy
	One Change materials arrive • 2 tables • Mascot • 2 tents • 300 medium boxes • 2 large boxes Game wheel		Delivery to be arranged by One Change Arrived June 17
Tuesday, June 21			
	One Change (Deb & Allison arrive in Whitehorse)	1:39 pm	Laura to pick up at airport Flight AC 8443
	One Change bag prep day		YECL basement
Wednesday, June 22	•		
	One Change (Stuart and son) arrive in Whitehorse	1:39 pm	Laura to pick up at airport Flight AC 8443
	One Change bag prep day		YECL basement
	Yukon News Ad		¼ page ad to run
Friday, June 24	Christine arrive at airport	1:39 pm	Flight AC 8443

Tour Timelines

Thursday, June 23	
Team 1	
	YECL Offices for continued set-up
Friday, June 24	
Team 1	
11 am	Depart Whitehorse Faro
3 pm	Arrive Faro
6:30 – 8 pm	Faro Public Event Tina Freake, Recreation Manager 867-994-2375
9 pm	Faro Accommodations Valley B&B
Saturday, June 25	
Team 1	
10: 30 am	Depart Faro for Ross River
11:30 am	Arrive Ross River
1 – 3 pm	Ross River Public Event between the band office and the store Sharon - 969-2277
4 pm	Depart Ross River for Carmacks
8 pm	Arrive Carmacks – Mukluk B&B
Sunday, June 26	
Team 1	
10:30 am	Depart Carmacks for Pelly Crossing
11:30 am	Arrive Pelly Crossing
1 – 3 pm	Pelly Crossing Public Event at Link Building Candace 537-3331
4 pm	Depart Pelly Crossing

Thursday, June 23	
Team 2	
8:30 am	Arrive at Airport - Alcan
9:30 am	Depart Whitehorse for Old Crow (Alcan Air)
11:30 am	Arrive Old Crow – pick up by
1:00-2:00 pm	Old Crow First Nations Meeting (Vuntut Gwitchin First Nation) Community Center
6:30-8:30 pm	Old Crow Community Event Community Center
9:00 pm	Depart Old Crow for Dawson City (Alcan Air)
9:30 pm	Arrive Dawson City Wendy and Dwight to deplane
9:30 pm	Pick up at airport by Yukon Hotel – Wendy and Dwight
10:00 pm	Depart Dawson City for Whitehorse (Alcan Air)
11:30 pm	Arrive Whitehorse
Friday, June 24	
Team 2	
1 – 2 pm	Dawson City Council Meeting at
Saturday, June 25	
Team 2	
1-3 pm	Dawson City, Public Event At the shelter at the weir.
Sunday, June 26	
Team 2	
	Return to Whitehorse

5 pm	Arrive Carmacks – Mukluk B & B
Monday, June 27	
Team 1	
	First Nations Meeting
1 – 2 pm	Village of Carmacks Meeting Council Chambers
6 – 7:30 pm	Carmacks Public Event
8:00 pm	Depart for Whitehorse
10:00 pm	Arrive Whitehorse
Tuesday, June 28	
Team 1	
11 am – 1 pm	Whitehorse Public Event
3 – 5 pm	Whitehorse city council meeting at Heritage room at City Hall.
Wednesday, June 29	
Team 1	
9:00 am	Depart Whitehorse for Burwash Landing
	Arrive Haines Junction
2 pm tentative	Burwash Landing First Nation meeting (Kluane First Nation)
4:30 – 6:30 pm	Burwash Landing Public Event Grace Southwick 334-3635 cell
7:30 pm	Depart Burwash Landing for Haines Junction
9:00 pm	Arrive Haines Junction – Alcan Motor Inn
Thursday, June 30	
Team 1	
1 – 2 pm	Haines Junction First Nation meeting (Champagne-Aishihik First Nation)
4:30 – 6:30 pm	Haines Junction Public Event
7:30 pm	Depart Haines Junction for Whitehorse
9:00 pm	Arrive Whitehorse
Friday, July 1	
	Teams meet at YECL offices to load vehicles
	Arrive at Shipyards Park for set-up

Monday, June 27	
10:30 am	Depart Whitehorse
12:30 pm	Arrive Teslin
1:30 – 2:30 pm	Teslin First Nation meeting (Teslin Tlingit Council)
4 – 6 pm	Public Event
7-7:30 pm	Village of Teslin council meeting at town office
7:45 pm	Arrive at Yukon Motel for overnight accommodations
Tuesday, June 28	
Team 2	
	Depart Teslin for Watson Lake
	Arrive Watson Lake
12-1 pm	Town of Watson Lake meeting
1:30 – 2:30 pm	Watson Lake First Nation meeting (Liard First Nation)
	Watson Lake Public Event
Wednesday, June 29	
Team 2	
	Depart Watson Lake for Whitehorse
	Arrive Whitehorse
Thursday, June 30	
Team 2	
	Prepare for July 1st event
Friday, July 1	
	Teams meet at YECL offices to load vehicles
	Arrive at Shipyards Park for set-up

10:00 am	Public Event start
	Public Event end
	Return to YECL Offices to unload
Saturday, July 2	
	Breakdown materials and sort

10:00 am	Public Event start
	Public Event end
	Return to YECL Offices to unload
Saturday, July 2	

Accommodations

Team 1
Laura Carlson & Wayne Tonsi (Burwash Landing/Haines Junction)

Date	Community & Location	Contact Info
June 24	Faro Valley B&B – 2 Rooms	994-2122
June 25/26	Carmacks Mukluk B&B – 2 Rooms	863-5232
June 29	Haines Junction Alcan Motor Inn – 2 Rooms	634-2371

Team 2
Wendy Scramstad & Dwight Redden/Jay Massie

Date	Community & Location	Contact Info
June 24	Dawson City 1 Room Eldorado, 2 Rooms Yukon Hotel (024125,024126,024127) Need 48 hour notice to cancel	993-5451
June 27	Teslin Yukon Motel (Rooms 13 & 14)	390-2575
June 28	Watson Lake A Nice Motel (YU1F086518)	536-7222

Cakes

Date	Community	Items Needed	Retailer	Date of Pick Up	Ordered	Contact #
Team One						
June 24th	Faro	4 cakes for aprox 50 people	Mrs. Boyle	110626	yes	
June 25th	Ross River	4 cakes for aprox 50 people	Tatchun General Store Carmacks open 7-11		yes pick up NOON	1 867 863 6171
June 26th	Pelly Crossing	4 cakes for aprox 50 people	Selkirk Centre Pelly		yes pick up NOON	1 867 537 3031
June 27th	Carmacks	4 cakes for aprox 50 people	Tatchun General Store Carmacks open 7-11		yes pick up NOON	1 867 863 6171
June 29th	Burwash Landing	6 cakes for aprox 50 people	Madleys		yes pick up NOON	1 867 863 2200
June 30th	Haines Junction	8 cakes for aprox 80 people	Madleys		yes pick up NOON	1 867 634 2200
Team Two						
June 25th	Dawson City	3 cakes for aprox 50 people	Dawson General Store		yes pick up NOON	1 867 993 5475
June 27th	Teslin	2 cakes for aprox 50 people	Superstore - Whitehorse		yes pick up 8:30am	456 6618
June 28th	Watson Lake	2 cakes for aprox 100 people	Watson Lake Foods		yes pick up NOON	1 867 536 2250

One Change Marketing

- 8000 Energy Kits
- t-shirts, volunteers - Short sleeve, quality cotton navy shirts. With subtle One Change embroidered (in white) logo on front and silkscreened logos, in white on back - please see "tshirt_final.pdf" for approval
- Light-weight jacket and golf shirts, champions and One Change staff. Olympic blue with subtle One Change embroidered (white) logo on front and heat transfer (white) on back, of three logos horizontally across the shoulder area - please see "golfshirt_horizontal_10in_final.pdf" for approval
- Golf shirt - navy, 100 wicking fabric with classic flat knit collar with subtle One Change embroidered (white) logo on front and heat transfer (white) on back, of three logos horizontally across the shoulder area - please see "golfshirt_horizontal_10in_final.pdf" for approval
- Tote - As mentioned the totes will be white with lime/green (green bottom band and carrying straps). The totes will be printed on both sides, logos all together on one side and the One Change mission statement on the other - please see "totebag_final_2.pdf" for approval.

Media Buy (YEC placing radio and facebook orders)

	June 15	June 17	June 22	June 24	June 29
Yukon News	**½ page $347.26**	**½ page $370.19**	**½ page $347.26**	**½ page $370.19**	**½ page $347.26**

Klondike Sun	**½ page $375.00**				
Radio	**Starts June 20 and runs through campaign (CKRW and CHON)**				
Facebook	**Starts June 20 and runs through campaign**				

Radio Scripts

- Version 1: Announcing the One Change campaign coming to communities across the Yukon.
- Version 2: Announcing the One Change campaign presents at the Canada Day celebrations in Whitehorse on July 1.

Signage

- Horizontal banner - (to be used at events to be hung from the tents) For placement on rear wind-wall of pop up canvas top tent. *One of horizontal banner or roll up banners to promote the prize give away (confirmed as a Whirlpool Energy Star® flat 22' fridge with pull out freezer drawer, to be provide by Whirlpool and supplied by Now Appliance & Bedding).*
- Roll-up banners - To be used at events and outside room for small meetings – showcase the campaign and sponsoring partners' logos
- Poster (to be used in the communities to help promote events) Posters announcing the details of the community events (time, date, location) to be sent to each Champion for distribution around communities as appropriate
- Podium sign (to be used at meetings as appropriate)
- Vehicle side and back wrap (to be use on the cube van that will travel from Whitehorse and back)

Additional Materials

- Hand crank display back board - Think grade 8 science fair table top exhibit to "test your human power" in the main panel and some stats and figures and partner logos on the two side panels
- Hand crank stickers - Update to be One Change branding. Simple designs.
- One change tri-fold mini brochures - To be used at events and outside room for small meetings – showcase the campaign and sponsoring partners' logos

UTILITIES CONSUMERS' GROUP

DEMAND SIDE MANAGEMENT PRESENTATION

The Canadian Institute of Wellbeing uses the concept of social inclusion when considering community vitality, one of the eight domains of the Canadian Wellness Index. The Index, which is currently under development, is a multi-faceted measure of the well-being of Canadian society.

> "A social inclusion framework focuses attention on the differential life experiences of all citizens within a community and in so doing, highlights the need to remove barriers to equal participation, free from discrimination. A socially inclusive society is thus one that develops the talents and capacities of all members, promotes inclusive participation in all walks of life, actively combats individual and systemic discrimination, and provides valued recognition to groups such as ethno-racial communities." (*Community Vitality: A Report of the Institute of Wellbeing*, 2009; p. 29)

A socially inclusive society is therefore one which cultivates the skills and abilities of its citizens and communities, and works towards a goal of equal opportunity and freedom from discrimination.



"I'm gonna pay my electricity bill while I'm here."

GOALS

- LOWER BILLS FOR ALL PARTICIPATING CONSUMERS
- ELIMINATE BARRIERS SO ALL RESIDIENTIAL CONSUMERS CAN ACCESS ENERGY CONSERVATION MEASURES
- PROMOTE LOWER COSTS THAN ALTERNATIVE ENERGY SUPPLY
- PRODUCE SYSTEM BENEFITS INCLUDING THE AVOIDED COSTS OF NEW GENERATION AND THE LOWERING OF EMISSIONS
- ROLES FOR ALL STAKEHOLDERS MUST BE CLEARLY IDENTIFIED (I.E. GOVERNMENT- ENERGY SOLUTIONS CENTRE, YUKON HOUSING CORPORATION, ENERGY MINES AND RESOURCES); UTILITIES-YUKON ENERGY AND YUKON ELECTRICAL; RATPAYERS/CONSUMERS; REGULATOR

LOWER BILLS FOR PARTICIPATING CONSUMERS

- ALL RATEPAYER GROUPS MUST BE INCLUDED IN DEVELOPING DSM PROGRAMS
- ALL RESIDENTIAL RATPAYERS MUST BE ENFRANCHISED TO PARTICIPATE IN SUCH PROGRAMS
- TARGETTED PROGRAMS WILL BE NECESSARY WITH NO EXCUSES THIS TIME

households living in poverty. The LICOs used for this report are as follows:

2005 after-tax LICOs, for urban areas with less than 30,000 people

Size of family unit	After-tax household income, 2005
1 person	12,899
2 people	15,700
3 people	19,548
4 people	24,388
5 people	27,772
6 people	30,799
7 or more people	33,827

Source: Statistics Canada, Catalogue No. 75F0002M

The following table provides a useful comparison for identifying family types that are more likely than others to experience severe poverty. Lone-parent families stand out, as they are more likely to be in severe poverty than other Yukon families.

Yukon households living below the low-income cutoff (LICO) in 2005

	Total households	Economic families in low income	
		Number	Percent
Total — All economic families	8,300	360	4.3%
Couple economic families	6,510	205	3.1%
Couples only	2,900	105	3.6%
Couples with children	3,300	100	3.0%
Couples with other relatives	305	10	3.3%
Lone-parent economic families	1,620	150	9.3%
Male lone-parent families	390	35	9.0%
Female lone-parent families	1,100	115	10.5%
Other economic families	170	0	0.0%

Source: 2006 Census

LOWER COSTS TO UTILITIES

- EACH DEVELOPED PROGRAM MUST ACHIEVE LOWER COSTS THAN ANY ALTERNATIVE SUPPLY OPTION
- EACH PROGRAM MUST BE EVALUATED ON A REGULAR BASIS (BI-YEARLY?)
- DSM PROGRAMS MUST NOT DRIVE INCREASED RATES

ROLES OF GOVERNMENT

1. ENERGY SOLUTIONS CENTER

A. DEVELOP TARGETTED PROGRAMS FOR MARGINALIZED CONSUMERS AND RENTERS USING GOVERNMENT FUNDS

B. DEVELOP CERTAIN PROGRAMS WITH HANDS ON INVOLVMENT USING GOVERNMENT FUNDS (I.E. RESIDENTIAL IN HOUSE STRATEGIES SUCH AS HOT WATER TANK TIMERS AND BLANKETS, LIGHTING ALTERNATIVES, ETC.

2. YUKON HOUSING CORPORATION

A. DEVELOP RETROFIT PROGRAMS FOR MARGINALIZED HOUSEHOLDS AND LANDLORDS USING GOVERNMENT FUNDS

B. DEVELOP NON-INTEREST LOANS FOR RESIDENTIAL RETROFITS TO MARGINALIZED FAMILY HOUSEHOLDS AND LANDLORDS WITH CONDITIONS

3. GOVERNMENT DEPARTMENT ENERGY, MINES AND RESOURCES

A. PROVIDE FUNDING FOR ESC AND YHC PROGRAMS FOR MARGINALIZED, RENTERS, AND LANDLORDS

B. DEVELOP STRATEGY FOR ALTERNATIVE SUPPLY IN DIESEL COMMUNITIES

C. COMPLETE POLICIES FOR IPP, NUGs AND NET METERING

D. NO FURTHER LEGISLATION REGARDING BUILDING DESIGN EITHER BY YTG NOR THE CITY.

THE UTILITIES-YEC AND YECL

- OFFER MAINSTREAM RESIDENTIAL DSM PROGRAMS
- DEVELOP DSM TECHNIQUES/PROGRAMS FOR GOVERNMENT, MUNICIPALITIES, COMMUNITIES, FIRST NATIONS, LARGER GENERAL SERVICE, MINES, ETC.
- INITIATE MORE EFFICIENT LOAD MANAGEMENT, DEMAND RESPONSE, DISTRIBUTION SYTEM OPTIMIZATION AND FUEL SWITCHING TECHNIQUES
- DEVELOP TIME OF USE RATES (I.E. SEASONAL)
- DEVELOP RATE DESIGN TO ENCOURAGE LESS USAGE (AFTER DSM PROGRAMS ARE IMPLEMENTED AND IN USE)

THE REGULATOR-YUKON UTILITIES BOARD

- TO ENSURE EACH DSM PROGRAM BENEFITS THE CONSUMER
- TO ENSURE THE PROGRAMS ARE COST EFFECTIVE WITH REGULAR MONITORING TO DEMONSTRATE EACH PROGRAM IS PRODUCING EXPECTED BENEFITS
- TO ENSURE ADEQUATE EVALUATION TECHNIQUES ARE ADDED TO THE FORMULA
- TO SET APPROPRIATE LEVELS OF DSM SPENDING
- TO OVERSEE COST RECOVERY AND INCENTIVES FOR EACH DSM PROGRAM

OTHER STAKEHOLDERS

- TO BE INVOLVED IN ALL ASPECTS OF DEVELOPING AND EVALUATING DSM PROGRAMS, INCLUDING LARGER CUSTOMERS SUCH AS MUNICIPALITIES AND MINES
- TO BE INVOLVED IN THE DESIGN, IMPLEMENTATION AND EVALUATION OF ALL DSM PROGRAMS, INCLUDING THE MINES
- TO HELP INFORM AND EDUCATE THE PUBLIC

Building a Culture of Conservation

beyond the utilities

Anne Middler, Energy Coordinator, Yukon Conservation Society

Yukon Conservation Society

April 19, 2012

Demand Side Management (DSM) What are we talking about? Why?

CONSERVATION = consuming/using LESS

EFFICIENCY = using BETTER/SMARTER

All sources of energy (even “green”) have impacts.

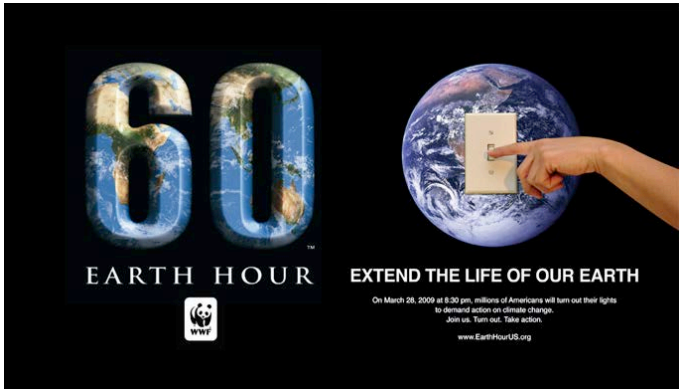
The best solution – reduce our demand for energy and use of resources.

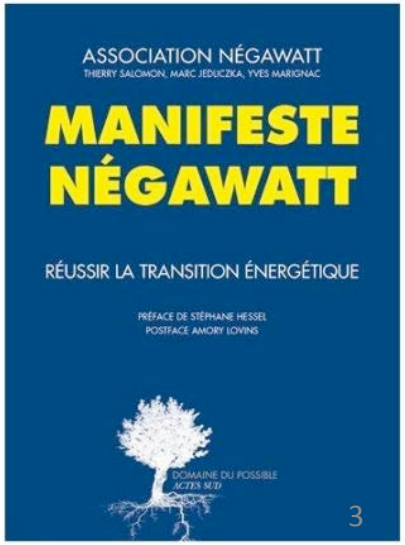


negawatt…. negawhat?

- Negawatt is a theoretical unit of power representing the amount of energy saved.
- The conserved energy is a negawatt, **the measure of power that is not used.**
- For example, Earth Hour.

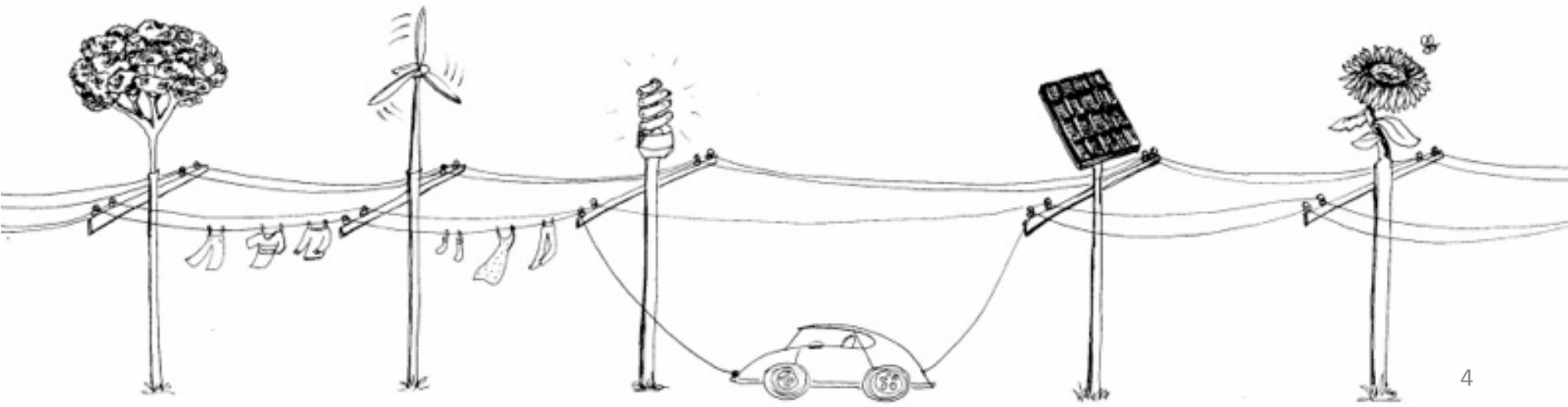
Negawatt Media





NEGAWATTS before MEGAWATTS

- Meet growing demand through DSM before new infrastructure
- Implement all strategies for reducing waste of energy regardless of perceived economics (YUB requirement)
- Let's aim for the technical potential, not just economic or achievable.
- If ratepayers don't pay for DSM programs, Government has to.
- Combination of stick and carrot (currently, more stick needed)



GOVERNMENT role and responsibility versus UTILITIES

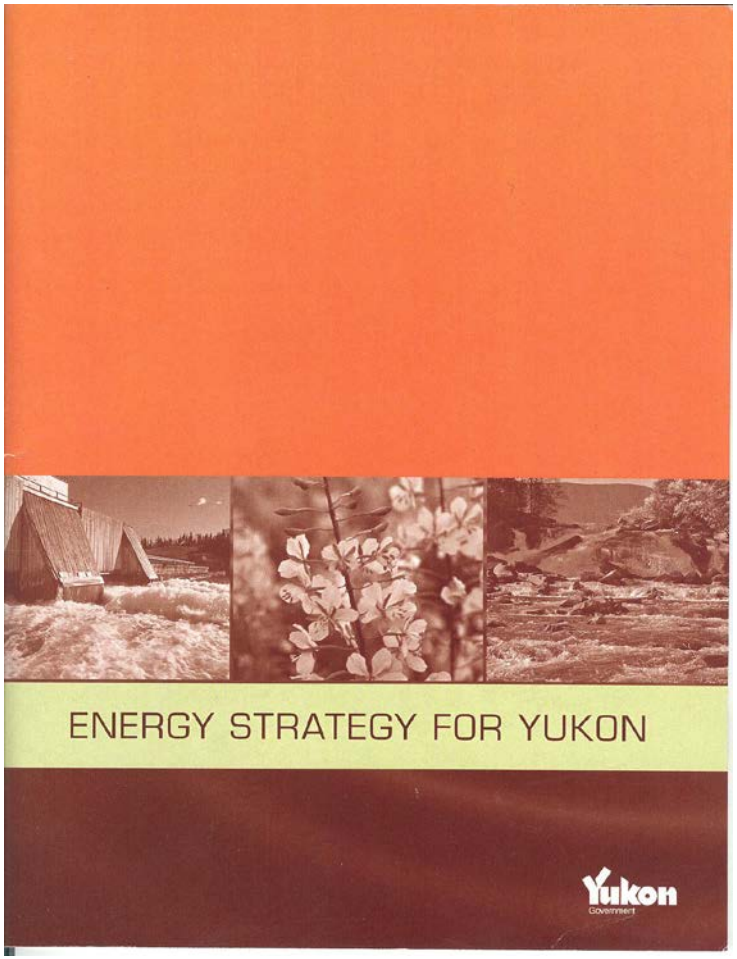
Utilities – directed by Yukon Utilites Board to investigate/implement DSM, but should DSM be led by utilities?

- …. seems counterintuitive for businesses to want to spend money to sell less and earn less money.

but the Yukon Government on the other hand…

- Energy Strategy for Yukon
- Climate Change Action Plan

Energy Strategy for Yukon



NUMBER ONE:

EFFICIENCY and CONSERVATION (E&C)

Goal

Energy efficiency and conservation will be a priority to reduce energy consumption, energy costs and emissions.

- Develop policies for E&C
- Deliver programs for E&C
- Incorporate E&C into decisions
- Improve E&C in communities
- Incentives for building retrofits
- Promote efficiency in new buildings
- Make industry more energy efficient

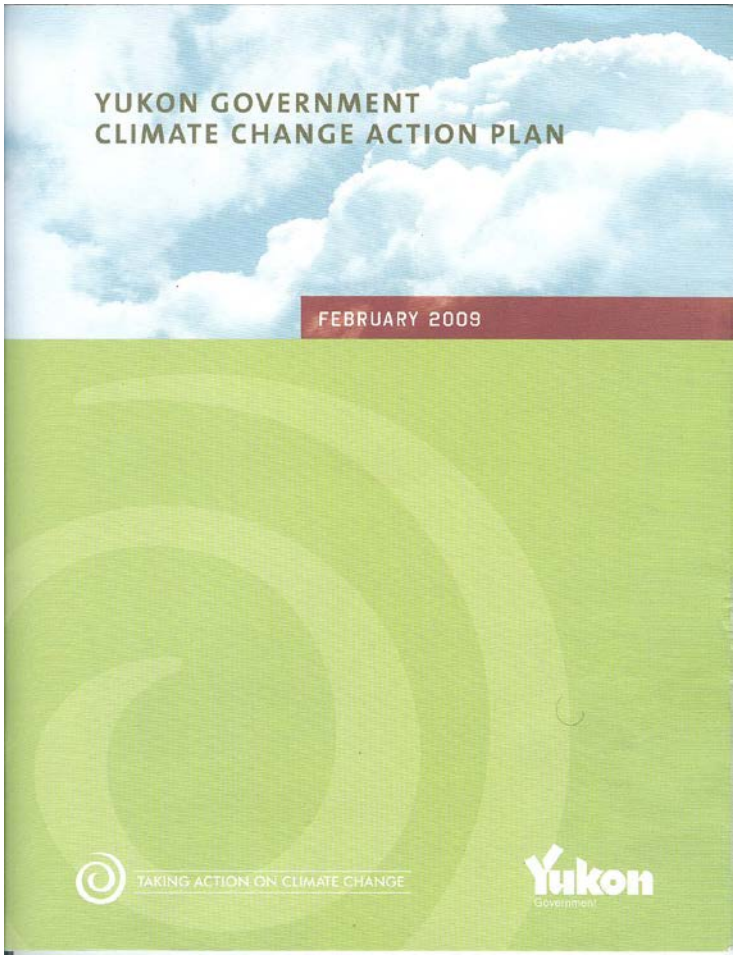
Climate Change Action Plan

Goal 3:
REDUCE OUR GREENHOUSE GAS EMISSIONS

Lead Yukon Action in Response to Climate Change

• Yukon Government operations to be carbon neutral by 2020.

• Emissions Targets – "…develop a Yukon-wide reduction approach."
• The target will be developed in a manner that shows our commitment to reducing our contribution to climate change…



Build a Culture of Conservation

- Individual/household behavioral change (not only to encourage a reduction in use of electrical energy, but all consumption of energy and resources (water, driving, buying etc.)



2011 Energy Diet Challenge Champions, the Kitchen-Kuiack family.

Shell-Canadian Geographic

Smart Meters – the power to save

- Empower individual and household consumers to manage their energy use and make smart choices.
- Start with a pilot project for interested people, monitor, publish results, implement broadly.



Price Signals – (stick!)

- Once people have a better understanding of their consumption, price signals can reduce/shift demand and recompense for the costs of producing more electricity.
- Ontario, Nova Scotia, have **time of use (TOU)** rates in place (costs more/pay a premium to use electricity in peak times, cheaper to consume off-peak)

off-grid diesel communities

- overhaul Rate Structure to encourage renewables
- ramp up all DSM programming

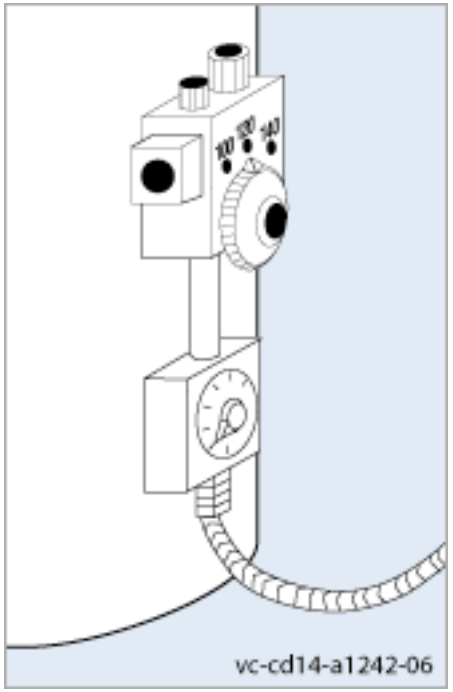


Old Crow Research Facility photo Kobayashi and Zedda Architects

Demand Shift – leveling the peaks

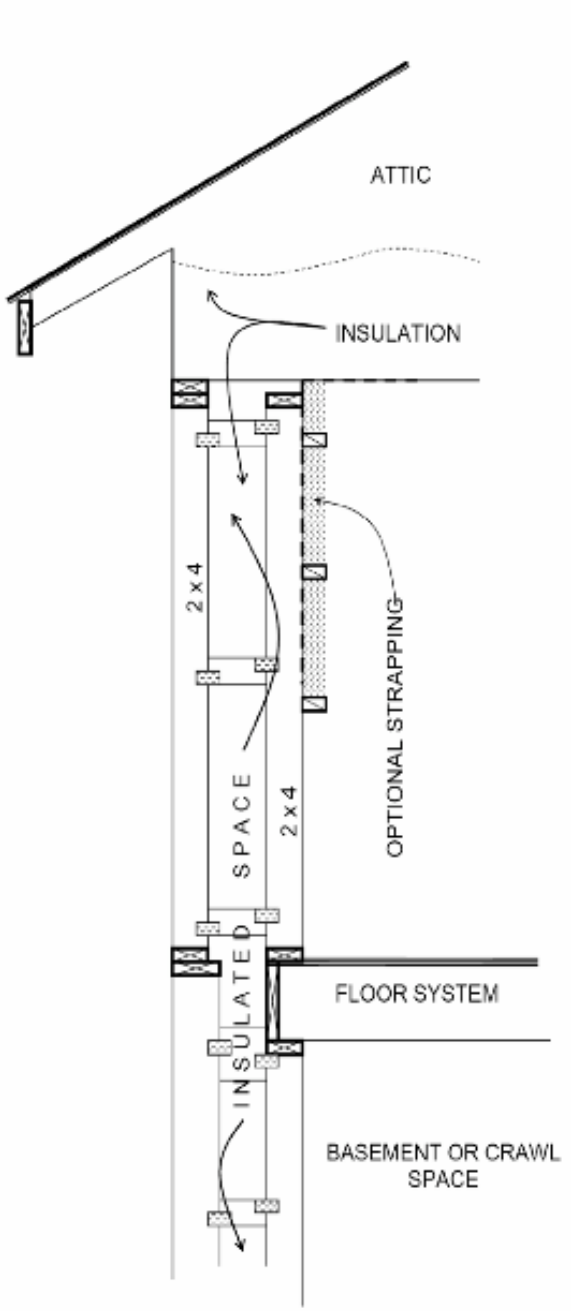
In 2002, Yukon Development Corporation completed a successful pilot program on hot water tank timers ("penguins").



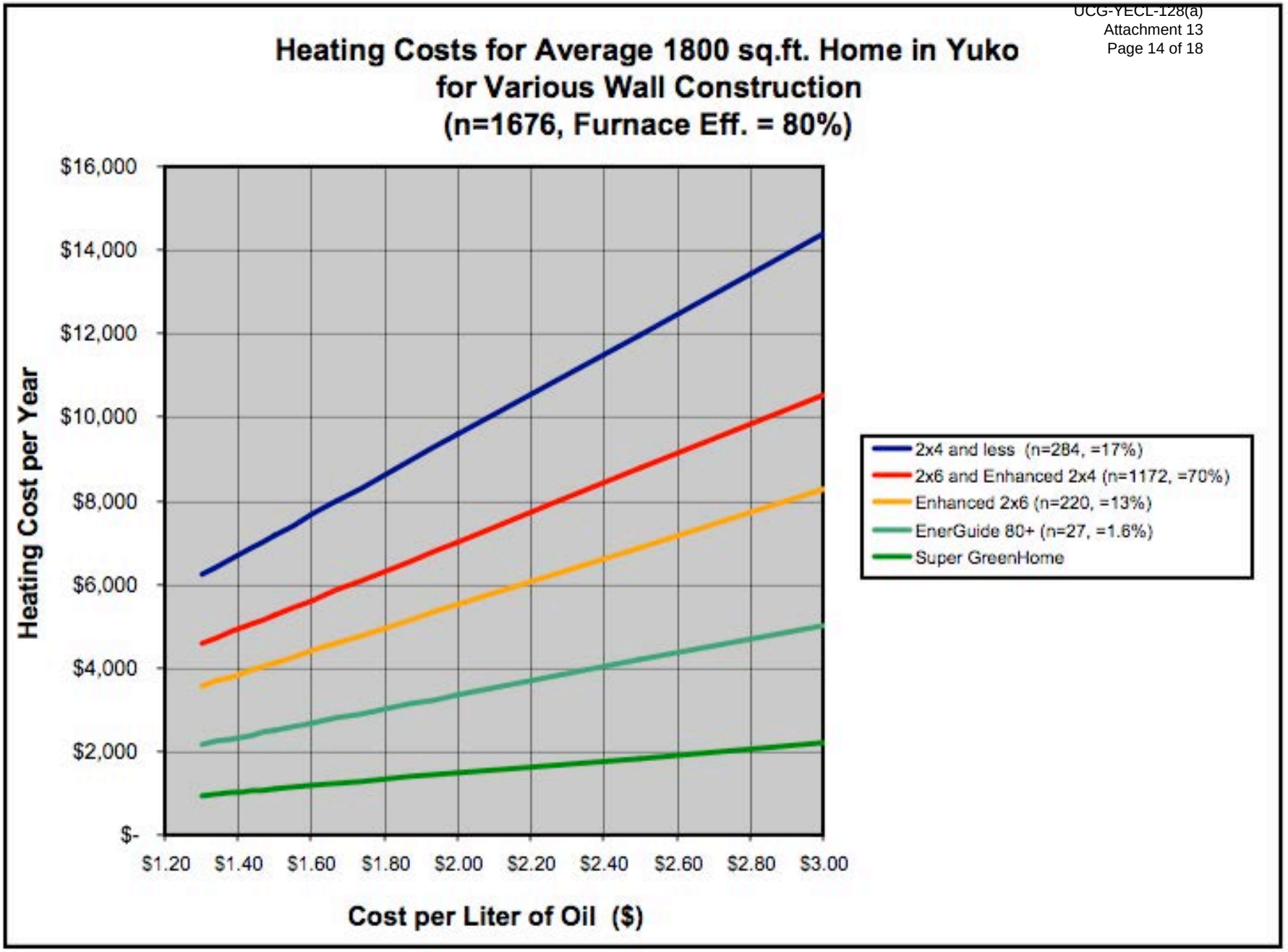


Strengthen Building Codes

– and serious investment in improving existing buildings

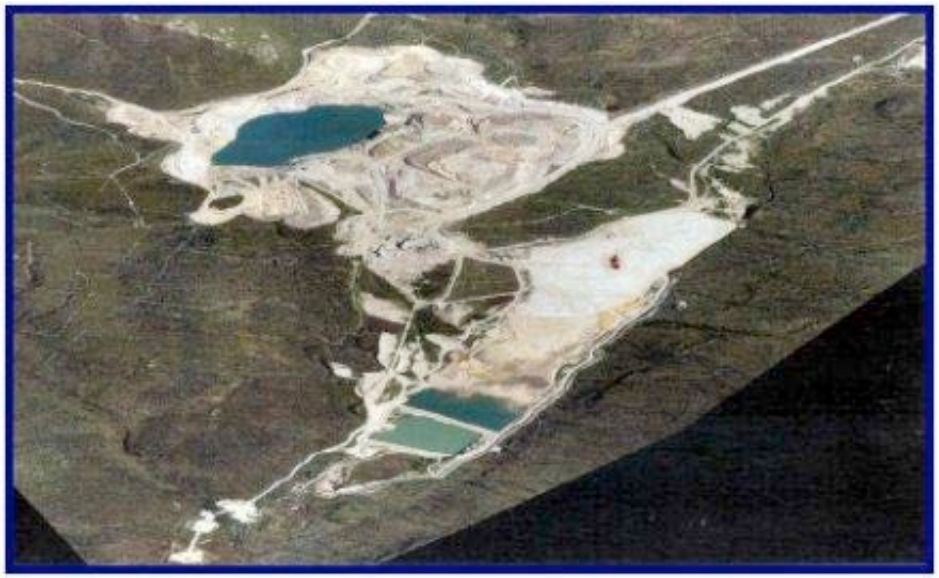


- Superinsulation (supergreen, doublewall) for comfort and safety
- Heat Recovery Ventilators (HRV) for healthy homes
- Retrofit existing building stock for safety and efficiency
- Improved code should allow for alternative construction and local materials, but restrictions for electric heat unless demonstrated efficiency


Heating Costs for Average 1800 sq.ft. Home in Yuko
for Various Wall Construction
(n=1676, Furnace Eff. = 80%)
Heating Cost per Year
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$-
$1.20
$1.40
$1.60
$1.80
$2.00
$2.20
$2.40
$2.60
$2.80
$3.00
Cost per Liter of Oil ($)
2x4 and less (n=284, =17%)
2x6 and Enhanced 2x4 (n=1172, =70%)
Enhanced 2x6 (n=220, =13%)
EnerGuide 80+ (n=27, =1.6%)
Super GreenHome

Industrial Demand Management

- Required energy audits/improvement for all existing and proposed mines
- Rate structure for power down incentive (peak and winter rates)
- Cost of Service (mines pay more than it costs to serve them? Really? Hmm.)
- Obligation to Serve (we *have* to serve them? Really? Hmm.)



Faro Pit and Rose Valley Tailings at the Faro Mine.

Supply Side to encourage conservation

NET-METERING help consumers become producers of green electricity (premium rates for export after household use of produced power)



Riverdale Net-Zero House in Edmonton

etcetera

- Commercial, Institutional, Industrial, Government.
- Net Metering/IPP/overbuild renewables to enable fuel switching (reduce emissions from transportation and space heating)
- Street lights, lighting, hot water, etc
- STORAGE/load management: batteries, heat sinks, heat recovery systems, Electrical Thermal Storage (ETS)
- Alternative heat (to oil or electricity) via district heating, ground/air source heat pumps
- cogeneration
- PUBLIC EDUCATION



THANK YOU



Yukon Conservation Society

Yukon Energy Charrette – March 7 – 9, 2011

The following notes do not represent a comprehensive "capture" of all that was discussed at the charrette, but are merely a compilation of the raw notes gathered during the event. A more complete and formal report will be available by late April.

Day 1 – Day Session

Identifying the Problem (issues, assumptions, restraints):

-We are running out of clean, affordable energy and we don't have a lot of time. Whole issue of energy security. This is a significant problem that is relevant to all of us.

-Status quo is not sustainable in meeting Yukon's energy needs.

-Growing population. Consumption is increasing.

-Isolated grid

-Economic growth: people, consumption, industry, transfers

-Environmental consequences

-Infrastructure is aging.

-Utilities need to be more efficient – load management and peak management

-There are some critical decisions to make in terms of energy future. Facing tough choices.

-We need/want more electricity without using diesel, without paying/risking a lot of money on renewables, and we should all use less/not be wasteful.

-meeting economic development goals

-uncertainties about how much generation is needed (unpredictable demand). We cannot predict the future. Highly variable.

-What are we willing to pay? We are not paying the true cost of power right now. We need a clear price signal. Low energy costs result in waste.

-Regulatory structure doesn't reward Demand Side Management (energy conservation)

-Need mechanism for Independent Power Producers.

-lack of winter energy. Power most needed in winter, when we have least amount of hydro.

-issue of rightsizing capacity/scalable

-boom and bust versus consistent growth.

-How do we mitigate risk of boom and bust economy?

-isolated grid, 2 utilities (small jurisdiction), small ratebase

-greenhouse gas emissions, climate change, peak oil

-can't always wait for business case

-peak demand; variability of demand

-expensive diesel generation – have to generate more power using diesel

-non-sustainable generation (diesel)

-meeting peak demand in winter

-limited short-term solutions to meet growing demand

-lack of certainty regarding long-term economic/load growth (lack of long term vision/planning) and uncertainty regarding climate change and hydrology

-The era of surplus is ending and a mining boom is underway.

-Is the issue an energy one or a social one (perhaps solution is behavioural and we can learn from the past)?

-Yukon Energy feels some obligation to supply new mines. Issue of Orders-in-Council and the Obligation to Serve. Issue of government policy.

-Question about mines: who bears the risk? Rates to mines should reflect the risk to Yukoners (price shock when mines shut down). Mines should be treated differently in terms of rates. To serve or not to serve mines is an issue that needs to be addressed. Many, many questions about who's responsibility it should be to provide power to mines. Clarify mandate of Yukon Energy.

-need to replace the attributes of diesel. However green doesn't seem feasible when we have diesel that works.

-need a mix that is flexible

-consider transition technology

-need about 100 gigawatt hours per year of clean power

-Electrical energy is becoming more popular.

-Consider ramping up biodiesel from trees.

-Will need to replace aging generators

-Expensive energy lowers our standard of living; social justice implications of expensive energy. Support people who are vulnerable.

-Affluent people don't mind if rates go up, but it's a problem for the less affluent.

-Rate inequality.

-There's a lack of transparency about costs and who pays.

-Seasonal challenges.

-There is a lack of consumer input because of a complicated regulatory language and process.

-Confusing regulatory structure; problem with accessibility of issues and process. Rate issue is complete and there is no consensus on this issue.

-Very complex and intertwined issues

-We don't clearly understand the non-mine load growth.

-Even without mines we soon will reach our limit of being able to supply Yukoners with electricity using existing renewable sources.

-Public education gap/need for broad public education and engagement

-Lack of common language based on facts – hard to have positive, informed dialogue with the public to build consensus

-People want to be part of the solutions but they don't know what to do.

-Lifestyle choices (energy hogs). Consumption is moving in the wrong direction (up). There is a culture of energy entitlement. Explosion of electronic devices, ghost loads, etc. Need to encourage energy efficiency (energy efficient appliances, etc.)

-Smart Meters are a must.

-Whitehorse is not a well planned community in terms of being able to use the least amount of energy possible.

-Different opinions on right/wrong decisions

-Need to focus on energy and not just electricity.

-Are we technologically ready for some choices (ex. electric cars)?

-IPP can be in competition with utilities; length of contract an issue

-use hydro as peak power and use solar with baseload

-new hydro issues: flooding First Nations land used for hunting and gathering

-must develop partnerships with First Nations and mines

What do we want Yukon's energy future to look like (what is the vision)? What are the opportunities and solutions?

Attributes of any energy choice should be:

1) **Affordability:**

-equity

-fairness/socially responsible

-good for Yukon

-Not necessarily the cheapest

-Can't have rate shock (anything above 15 percent per year).

-economically responsible

-per capita; family fair consumption

-use energy to build community prosperity

-true cost of power vs. affordability. Linked to government policy.

-small business – affordability and reliability are the main issues

-challenge of shared responsibility

-Need block rate structures to send energy conservation signal

-Must balance being equitable among customer classes with conservation.

-Rate design: need trade-offs.

-Obligation to serve at what price? Should the mines pay the full cost for their electricity?

-Real cost of energy opens door to discussion about fairness of rates

2) Reliability:

-Boom and bust economic...need to plan for that.

-Security of supply of fossil fuels unknown.

-Competing interests: how to balance/choose/find win-wins. Must balance interests.

-need predictable cost

-need capital/operating cost ratio that makes sense

-further investigate trans-border energy links with B.C. and/or Alaska.

-reliable in both winter and summer

-use renewable to provide baseload energy

-Mines should continue to be asked to subsidize infrastructure.

-speed to market

3) Flexibility:

-limit/show growth of change: is this under our control?

-Any short term goals must lead to long term solutions.

-any solution needs to be accepted by the Yukon public.

-assets should be built with future needs in mind (ex: Carmacks-Stewart transmission line should have been built bigger)

-There needs to be a greater generation mix. Must diversify.

-Yukon Energy needs to go beyond electricity and be more about energy; should get into district heating.

-Need to be open and flexible for emerging technologies.

-Coordinate with other initiatives.

-Power sources must be incremental.

-diverse suppliers model

4) Locally maintainable

-vertical integration using local resources

-need to consider limits to growth

-Does it improve economics in Yukon? Needs to support economic development.

-technical limits/skills

-technology available on a suitable scale?

-leadership in technology, Demand Side Management (energy conservation), innovation, policy, etc.

-Provide access for small energy producers to contribute to the system.

5) Environmentally responsible (clean?)

-Why diesel is not a good choice: greenhouse gas emissions, security of supply, cost (price fluctuates)

-meet needs sustainably, but people have to recognize and explicitly acknowledge that there will be tradeoffs against competing interests (i.e., new generation facilities will have to be built because Demand Side Management - conservation and efficiency - won't meet all the demand)

-need to look at life time costs of projects when determining if they are clean or green (cradle to grave)

-opportunity to look at green building codes for Whistle Bend, spruce bark beetle district heat, carbon neutral

-look at total Yukon greenhouse gas reductions.

-don't just look at greenhouse gas emissions. There are other costs that you can't put a dollar value on.

-We need to move away from fossil fuels and we need to reduce our carbon footprint. Need to consider footprint size in whatever Yukon Energy does

-All Yukoners need to take personal responsibility for their energy usage. Small changes embraced by many can make a big difference. We should all be less wasteful.

-I want to feel I am doing something to help the environment.

-More 'stick' and less 'carrot'. Emphasize individual responsibility.

-We need to send price signals that will lead to energy conservation.

-We need to be super green.

-Demand Side Management ideas such as hot water heaters in homes controlled by Yukon Energy; interruptible electric heat

-Yukon Energy needs to develop more renewable energy.

-Smart Metering

-Offer programs for heat pumps.

-Award people for efficient use of energy.

Day 1 – Evening Session

Comments from the public on the work done by charrette participants on Day 1:

-Whatever choices are made need to be flexible and scalable.

-There needs to be a consistent strategy

-There is an opportunity to replace diesel with renewable

-Must figure out the solutions

-We need to know the true cost of electricity. (We don't pay true cost but we also don't pay the true cost of oil).

-What is the breakdown in electricity supply?

-Opportunity to meet greenhouse gas emissions targets

-Good process. Glad Yukon Energy is doing this.

-Make money off distributed generation (i.e. solar panels on people's roofs)

-Individual systems (net metering)

-Challenge people: the solution is low hanging fruit (energy conservation)

-Look at the big picture

-People are too concerned about the past decisions and not the future ones.

-Twenty to thirty year solution: Atlin, Gladstone, Marsh.

-Who profits from rate increases?

-How long does it take to build new generation of various sizes?

-Let Western Copper build/provide their own power (liquefied natural gas) and then Yukon Energy could buy some of it for other Yukoners

-Should public be aware of rate plan changes when fossil fuel heat is more expensive than electricity?

-Information to the public needs to be clear

-In terms of decision making criteria, consider the following additional things: 1) innovation; 2) politically independent; 3) local; 4) scientifically objective; 5) incent economic and resource development; 6) local economy benefit/create community revenue stream and jobs; 7) research new technologies/innovation for cold climates and include research and development centre; 8) synergies with other systems i.e. southeast Alaska/BC Hydro

Day 2 – Day Session

Playing the Energy Game (alternatives and consequences of choices):

Scenario: the existing energy generation with hydro is 400 GWh/yr. Groups were asked to find new energy for 2015 (additional 144 GWh/yr), 2025 (additional 273 GWh/yr), and 2050 (additional 650 GWh/yr). Participants were to base their choices on the general criteria of affordability, reliability, flexibility, and environmentally responsible. A possible 5th consideration would be "Is it local?"

Choices, in order of preference:

2015:

-Hydro Enhancement (Marsh Lake)

-Demand Side Management

-Wind

-Biomass

-Hydro Enhancement (Atlin Lake)

-Hydro Enhancement (Gladstone)

-Liquefied Natural Gas

-Solar

-Waste to energy

-Diesel enhancement

-Individual district generation

-On site generation at large mines from pipeline

2025:

-Solar and wind (tied for first place)

-Liquefied Natural Gas

-biomass, medium sized hydro and Demand Side Management (tied)

-geothermal

-small hydro/hydro enhancements and micro-nuclear (tied)

-vehicle battery and waste to energy (tied)

-Connection to BC grid

-spinning reserve, Independent Power Producers, and large hydro (tied)

2050:

-solar and new hydro (tied)

-Demand Side Management, connected to grid, liquefied natural gas (pipeline), biomass (tied)

-nuclear, new technologies, geothermal and electric transportation (tied)

Day 2 – Evening Session

Dot-mocracy Game: members of the public were invited to make their choices as to energy options for 2025 and to vote for their choices using "dots" with 1 dot = 1 vote.

Results of game, in order of preference:

-Demand Side Management/energy conservation (43 votes)

-biomass (40 votes)

-wind (35 votes) <21 votes for Ferry Hill and 14 votes for Mount Sumanik>

-new hydro medium-scale (31 votes)

-nuclear (24 votes)

-solar (23 votes)

-geothermal (15 votes)

-transmission: B.C. or Alaska (15 votes)

-Marsh Lake storage (13 votes)

-New Hydro – small scale (13 votes)

-Atlin storage (12 votes)

-waste to energy (7 votes)

-Gladstone diversion (5 votes)

-natural gas (5 votes) <on site generation 3 votes and conversion 2 votes>

After using dot stickers to choose favoured options, here are some general observations from members of the public who participated in the game:

-There were no real micro options (options for individual homes).

-Nuclear didn't make the list, but it really should have. It is practical. It works.

-We needed to know the cost per kilowatt hour (dollar signs tried to show that but they weren't all that helpful).

-Demand Side Management (energy conservation) is a no-brainer because it's part of the immediate solution.

-A number of people were looking for synergy between systems when they were making their choices.

-A number of people voted with two to four stickers on each of several options. Only a few put five or more stickers on any one option. Only a few put just one sticker on any one option.

-Would like to see Yukon Energy using Smart Meters

-Yukon Energy should look at time of day and time of year when considering Demand Management (ex: mines should be cut off from the grid in the winter)

-Biomass provides ready employment and is carbon neutral, clean and sustainable (long term).

-There should have been an option for small micro-generation (customer owned) or co-generation for residential, business and institutions.

Day 3 – Day Session

Principles of decision-making:

-All options less per kilowatt hour than diesel

-All options must ensure reliability, flexibility, environmental responsibility, affordable

-Independent Power Producer options should be considered

-Alternative/local generation should be considered

Risks of Decisions

-Planning dollars

-Yukon Utilities Board

-Government legislation (Orders in Council)

-Energy security

How should Yukon Energy engage with the public from this point forward?

-Make public the specific principles of decision making and promote the four objectives (reliable, affordable, environmentally responsible, and flexible)

-Consolidate charrette outcomes into a summary report that is shared with the public.

-Propose your suggested energy portfolios within six months or less.

-Help people understand how the on-going engagement process will direct Yukon Energy's decision making. Report back one month out, two months out, six months out, etc.

-Show that the charrette has teeth.

-Promote public ownerhip. Show what mileposts were established at the charrette and providing periodic reporting and progress reports to show results. Accountability.

-Repeat charrettes with more emphasis on getting public out and help people feel they can make a difference.

-Provide detailed economic analysis about suggested options: help us understand how you come to the conclusions you will read in the 20-year resource plan

-Bring draft resource plan to a public meeting

-Provide Yukoners with regular updates on the process

-One day a year information sessions

-Major outreach every second year (on a week-end when it is convenient for more people)

-There needs to be broad engagement: youth, industry, First Nations, public, stakeholders, etc. Partners could include Energy Solution Centre, Yukon College, Yukon Conservation Society, municipalities, schools, retailers, non-government organizations, Yukon Housing (building standards), etc.

-Create a working group to hash out changes; create an energy working group of local people including various stakeholders and members of the general public to continue working on these issues with Yukon Energy. This group would be led by Yukon Energy.

-Yukon Energy involvement with schools, but also get the students involved in the planning.

-Presentations in every school

-Energy parade

-Maybe the MAD (Music, Art and Drama) students at Wood Street school could create an art piece that promotes energy conservation (work with the Experiential Science class) on this.

-School credits for doing energy related assignment

-paid ambassadors

-scholarships

-fix up schools

-Hold competitions among the general public re: energy use and energy conservation.

-Turn every consumer into a producer of energy

-mail out dot-mocracy so others can vote

-mail out a false high bill to shock people and get them talking

-tours of dams

-brief email updates

-need to help people over come apathy; turn off the power should be their first choice

-Build trust, continued dialogue.

-People need to see action now, based on what Yukon Energy heard at this charrette.

-Make an energy video game like SIM City.

-Smart phone app to provide information about energy consumption. Could show what sources we are using at any given time (hydro, diesel, etc.)

-Develop visual representations of energy information.

-hold 'brown bag lunch' sessions.

-Public needs to be engaged and better educated about energy issues. In particular, there needs to be better communication from Yukon Energy and Yukon Electrical Company Limited with regards to energy conservation.

-People need to understand that energy issues are important to everyone and affect everyone.

-Public meetings in more communities

-Immediate action on Demand Side Management

-Yukon Energy could empower people to take charge/control of their energy consumption (be the change).

-Work with landlords and tenants to look at creative financing in order to implement Demand Side Management (energy efficient appliances, building attributes and designs like windows, doors and retrofits)

-More school and office Demand Side Management programs

-Communicate directly with individual companies and employees about energy conservation.

-Use the charrette participants to communicate what was learned here...everyone should tell two or more people so that the message can spread.

-Bring the Yukon government to the table as leader of the multi-stakeholder group. Also bring large clients/mines into the conversation.

-Get ideas from other jurisdictions

-Make the information relevant and real for youth

-Train students who can then present information to other students (skill development). Provide cash incentives to schools based on student work. Ambassadors – informed 'audits' with student swat teams.

-In school energy fair

-Put information on bills telling people what they would be paying if they were charged the true cost of providing them with power

-"Power Nut" super hero

-Need fun projects to educate the public

-Get parents talking to kids and kids talking to parents about energy issues

-Public meetings: tap into existing meetings (partnerships)

-Pick visible, relevant wedge (ex: 'schools are energy hogs') to focus public engagement, training, public relations. This also have the effect of getting youth involved.

-Select action –oriented project to increase the public's knowledge about energy and energy conservation (ex. school audits, door to door campaigns, etc.)

-People need to have more of a basic understanding about the Yukon energy situation. They need to understand tradeoffs/rationale for decisions, and that tradeoffs are unavoidable.

-connect Yukon Energy decisions to feedback from the public (explain rationale for Corporation's choices).

-Regular section in the Yukon newspapers.

-There needs to be more advertising/public information regarding Demand Side Management.

-Solar powered bill boards telling people their energy consumption and that Yukon Energy is having to run diesel.

-Encourage change in policy and in Public Utilities Act

-Politicians need to be engaged

-website/blog, but not just social media. There is a place too for flyers, ads, etc.

-trade show

Day 3 – Evening Session

Dot-mocracy Game: members of the public were given 16 dots and asked to place them on their favourite suggestions that came from the Day 3 day session regarding how Yukon Energy should engage the public from this point forward.

Most popular suggestions:

-Partnerships: involve Yukon Housing Corporation, Energy Solutions Centre, businesses, First Nations, etc. In energy conservation programs – 19 votes

-summarize resource plan and make it readily available – 15 votes

-Produce energy-related video game like Civic Mirror or Sim City (but check first to see what already exists before developing new material) – 13 votes

-Form an energy working group made up of stakeholders and ordinary Yukoners – 12 votes

-Small but consistent communications is key – 8 votes

-provide regular and ongoing updates and opportunities for further public input – 8 votes

-Develop energy course for schools – 8 votes

-Charrette every two years – 6 votes

-let's keep talking – 5 votes

-Information needs to be visual, easy to understand, and needs to 'hit home' with people – 5 votes

-Blog/Facebook/web – 5 votes

-Solar powered sign that shows how much energy is being consumed in real time (and when we're into diesel) – 5 votes

-Fun competitions between families or between communities – 5 votes

-Convene in six months to update participants on progress – 4 votes

-Take message to other Yukon communities – 3 votes

-Electricity Day or Energy Fair – 3 votes

-Door to door DSM campaign – involve youth – 2 votes

Other suggestions that were different from what was proposed during the day session:

-Produce an annual information sheet for the fridge or cupboard that shows the cost per kilowatt hour of dryer, fridge, TVs, etc. So consumers can easily see the impact and cost of use – 2 votes

-Estimate costs and timeline for options discussed at charrette – 3 votes

-Ask consumers if electric heat is OK or decide that the seasonal load can work – 5 votes

-Consumption chart on web needs to be easy to find and read – 2 votes

-Notice to radio stations when we're burning diesel – 2 votes

-Show us how full our reservoirs are – 3 votes

Residential Workshop - November 15, 2011

Registered	Name and organization
	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Doug McLean - Energy Solutions Centre
x	James Wigmor - Energy Solutions Centre
x	Sean McKinnon - Energy Solutions Centre
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
	Hector Campbell - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Dwight Redden - YECL
	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
x	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
x	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Roy Whiten - Green Heat Technologies Ltd
x	Northerm Windows and Doors (David or Russ)
x	Wayne Wilkinson
x	Terry R-Holway (CAFN)
x	John Maissan of Leading Edge Projects
x	JP Pinard
x	Forest Pearson
x	Viviane Tessier - Remax
x	Jonathan Kolot - builder/ framer
x	Paulette Reust - Coldwell Banker
x	Karol Campbell - Coldwell Banker
x	Ray Sabo
x	Scott MacDonald - Igloo
x	Elain Whytte - Mayor of Carmacks
x	Janet Patterson - YEC
	Sow's Ear Builders and Energy
x	Yannick St-Jean - Ever Green Homes and Construction
x	Richard Corbet - Yukon Government
x	Brian - Kiwi Construction
x	Jen Meurer - Energy Mines and Resources
x	John Stricker

Commercial & Institutional Workshop - November 16, 2011

Registered	Name and organization
	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Doug McLean - Energy Solutions Centre
x	Marianne Gregoire – Highways & Public Works
	Rebecca World/ Shanna Epp – Climate Change Secretariat
	Helen Booth—Economic Development
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
x	Gord Debruyn YG
x	Hector Campbell - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Cameron Osler - Intergroup
	Dwight Redden - YECL
x	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
x	Geoff Quincy - City of Whitehorse
	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Rick Karp or Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Fraser Smith Northern Climate Engineering (NCE)
x	Jeffery Pike - NCE
x	Dylan Stewart - NCE
x	Dyson Hale - NCE
x	Roy Whiten - Green Heat Technologies Ltd
x	Northerm Windows and Doors (David and Russ)
	ArcRite Northern
x	John Maissan - Leading Edge Projects
	JP Pinard
x	Ray Sabo ESC
x	Elain Whytte - Mayor of Carmacks
	Janet Patterson - YEC
x	Rod Savoie - FSC Architects and Engineers
x	Mike Simon Property Management
x	John Stricker
x	Jen Meurer - Energy Mines and Resources

Customer-Side Renewable & Alternative Energy Workshop - November 17, 2011

Registered	Name and organization
	Shane Andre – Energy Solutions Centre
x	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
x	Krista Roske - YEC
x	Hector Campbell - YEC
	Ed Mollard - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Cameron Osler - Intergroup
x	Marc-Andre Lavigne - YEC
x	Shannon Mallory - YEC
	Dwight Redden - YECL
	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
	Geoff Quincy - City of Whitehorse
x	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Rick Karp or Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
x	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Wayne Wilkinson
	ArcRite Northern
x	John Maissan - Leading Edge Projects
x	JP Pinard
	Jonathan Kolot - builder/ framer
x	Ray Sabo
	Janet Patterson - YEC
	Sow's Ear Builders and Energy
x	Terry R-Holway (CAFN)
	Laura Spicer -INAC
	Lawrence Ignace - INAC
x	James Wigmore ESC
x	Doug McLean ESC
x	Sean McKinnon
x	Shirley Abercrombie - Energy Mines and Resources
x	Janet Patterson - YEC
x	John Stricker

CPR Methodology Workshop (May 3, 2011) - Attendees

Morning Educational Session 8:00 am - 12:00 pm

1. Shirley Abercrombie
2. Dwight Redden
3. David Morrison / Piers McDonald
4. Shane Andre
5. Manon Moreau
6. Cathy Cottrell
7. Doug McLean
8. Marianne Gregoire
9. Rebeccal World
10. Eric Schroff
11. Helen Booth
12. Clare Robson
13. Juergen Korn
14. David Black
15. Greg Finnegan
16. Wayne Tonsi
17. Phil borgel
18. Laura Carlson
19. Wendy Scramsted
20. Krista Roske
21. Hector Campbell
22. Ed Mollard
23. Tom Debolt
24. Wesley Marsh
25. Mona Politt-Smith
26. Cameron Osler
27. Marc-Andre Lavigne
28. Janet Patterson
29. Lawrence Ignace
30. Wayne Tuck
31. Mike Gau
32. John Pattimore
33. Rick Karp
34. Mike Wark
35. Laurie MacFeeters
36. Anne Middler
37. Roger Rondeau
38. John Maisson
39. Steve Mooney
40. Arcrite Northern
41. Archtech Ventillation
42. Certified Heating and Services
43. Duncan's Limited
44. Fred's Plumbing and Heating
45. FSC Architects and Engineers
46. Hurlburt Enterprises
47. Kobayashi and Zedda Architechs Limited
48. Northerm windows and Doors
49. Olsen's Resource consulting
50. Sourdough Plumbing and Hot Water Heating
51. Sow's Ear Builders and Energy
52. Wayne Wilkinson
53. Dynamic systems
54. Yukon Contractors' Association
55. Martin Crill
56. Saskia Bunicich
57. Bob Edzerza

Lunch (working lunch with Marbek and Construction reps) 12:00 – 1:30 pm

1. Paul Robillard
2. Chris Pulfer
3. Jack Habart
4. David Shipley
5. Arcrite Northern
6. Archtech Ventillation
7. Certified Heating and Services
8. Duncan's Limited
9. Fred's Plumbing and Heating
10. FSC Architects and Engineers
11. Hurlburt Enterprises
12. Kobayashi and Zedda Architechs Limited
13. Northerm windows and Doors
14. Olsen's Resource consulting
15. Sourdough Plumbing and Hot Water Heating
16. Sow's Ear Builders and Energy
17. Wayne Wilkinson
18. Dynamic systems
19. Yukon Contractors' Association
20. Juergen Korn

Afternoon Bilateral Meetings 1:30 – 4:30 pm

DSM program managers Meeting

- Focus is on better understanding of expected future program directions, lessons learned to date, etc. This is to ensure that we design the study structure (eg. sub sectors, end uses etc. in a way that will be most useful to the Yukon. Also to ensure that best available program and market data is identified and accessed.

1. Marbek Rep
2. Wayne Tonsi
3. Krista Roske
4. Shane Andre/Cathy Cottrell
5. Janet Patterson
6. Laura Carlson
7. Marianne Gregoire
8. Juergen Korn
9. David Black

Sales Data Meeting

- Focus is on details of sorting and exchanging customer sales into the sub sectors etc. discussed in the morning session. Discussions will involve strategies for dealing with imperfect date. Also to ensure that best available program and market data is identified and accessed.

1. Marbek Rep
2. Wendy Scramsted
3. Tom Debolt
4. Wesley Marsh
5. Greg Finnegan
6. Mona Politt-Smith

Load Forecast Meeting

- Need to understand current YEC/YECL assumptions re: future load growth, what level of detail data is available at, etc. This will enable us to align the study's reference case with electrical load forecasts.

1. Marbek Rep
2. Cameron Osler
3. Helen Booth
4. Randy Morgan

System Planning Meeting

- Need to understand system constraints, technology options under consideration to ensure that study structure and assumptions align with Yukon needs.

1. Marbek Rep
2. Hector Campbell
3. Marc-Andre Lavigne
4. Phil Borgel
5. Manon Moreau

Appendix B Market Characterization Methodology

ICF Marbek
an ICF International Company

Market Research Methodology

Client: Yukon Energy Corporation (YEC)
Yukon Electrical Company Limited (YECL)
Re: Market Research Methodology
Project: Residential and Commercial DSM Program Design
Version: September 24, 2012 – As delivered

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1. Sub-sector Research Focus

The following table presents the three sub-sectors that were researched. Further information can be found in the *Team Discussion Paper on Program Focus*.

It should be noted that the sub-sectors presented herein differ slightly from those presented in the discussion paper. This minor change was incorporated to optimize the use of resources and avoid "pre-establishing" the program design.

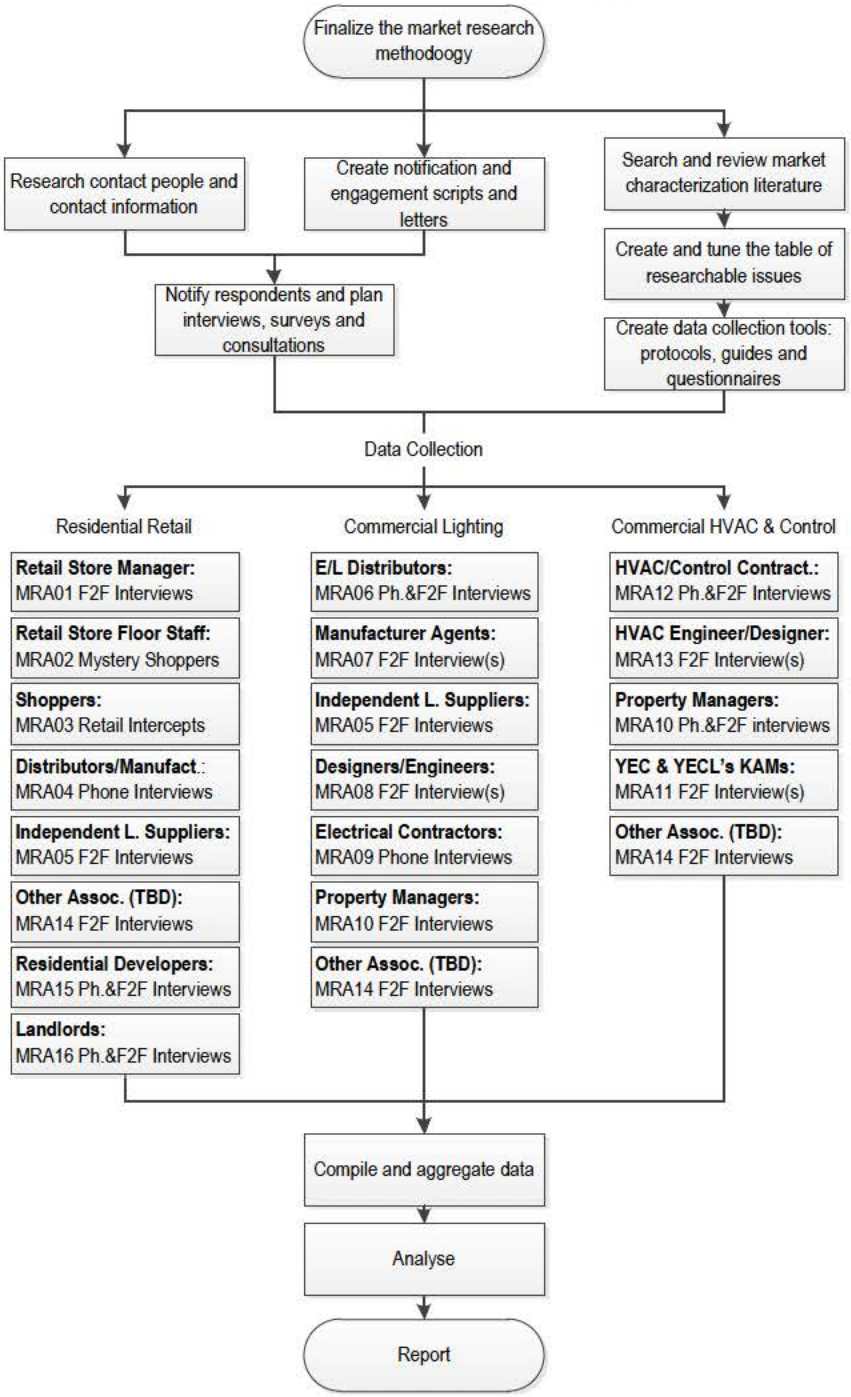
Exhibit 1 Sub-sector Research Focus

Sub-sector	Description
Residential Sector	
RR - Residential Retail	We initially envisioned a program that would directly engage retailers. The program would target typical equipment sold by retailers, both in-store and online. Equipment that could be targeted included lamps and fixtures (*maybe* including self-ballasted screw-in CFL), domestic appliances such as clothes washers and refrigerators, programmable thermostat, and low-flow showerheads.
Commercial Sector	
CL - Commercial Lighting	We initially envisioned a program that would directly engage with electrical and lighting distributors. Rebate programs have proven to be quite effective in the commercial lighting sector. The program would increase the penetration of energy efficient equipment.
CHCR - Commercial HVAC & Control Retrofit	We initially envisioned a program in which contractors would proactively develop business with commercial building owners and managers to: 1) identify opportunities in HVAC and controls; 2) convince building and management owners to invest; and, 3) implement either low-cost/no-cost measures, or capital-intensive conservation measures, or both. Retro commissioning and energy auditing are two pathways to achieve items 1 and 2 stated above. We wanted to research the market readiness and interest in such an approach and, in the absence of readiness, the tolerance of the market for direct intervention by YEC & YECL.

2. General Market Research Approach

Exhibit 2 outlines the major steps in the design and implementation of the market research activities as well as the identified participants.

Exhibit 2 General Market Research Approach



3. Sampling

Exhibit 3 outlines the proposed sample sizes, the actual sample sizes, and a justification for the gap between proposed and actual. Population estimates were made to establish the targets.

Exhibit 3 Sampling Plan

Market Data Source (Market Actors)	Market Research Activity	Population Estimates	Sample Targets	Sample Actual	Justification
RR – Retail Store Managers	F2F Interviews (MRA01)	10	4	4	Nothing to report.
RR – Retail Store Floor Staff	Mystery Shoppers (MRA02)	1,000	20	6	Only six relevant stores in Whitehorse; 3 lighting; 3 appliances.
RR – Shoppers	Retail Intercepts (MRA03)	20,000	30	22	More challenging and time-consuming than expected.
RR – Suppliers (All types. To be narrowed down.)	Phone Interview (MRA04)	50	2	0	Was cancelled. Most of retailers interact with a website rather than with individuals
RR & CL – Independent Lighting Retailers	TBD – Likely F2F Interviews (MRA05)	15	3	1	Only one was found at the time.
RR – Residential developers / contractors	F2F or phone interviews (MRA15)	6	0	3	These interviews were added mid-course during the study.
RR – Landlords	F2F or phone interviews (MRA16)	10	0	4	These interviews were added mid-course during the study.
CL – Electrical and/or Lighting Distributors (E/L Distributors)	F2F Interviews (MRA061)	3	1	2	The two distributors with branches in the YT responded. 6 other national distributors w/o a YT branch were contacted but declined to respond.
	Phone Interviews (MRA062)		2	0	
CL – Manufacturer Agents	Phone Interviews (MRA07)	2	1	1	Nothing to report.
CL – Lighting designers and/or Engineer	F2F Interview (MRA08)	3	1	1	Nothing to report.
CL – Electrical Contractors	Phone Interviews (MRA09)	26	6	5	Response rate was low. All 26 contractors were contacted.
CL & CHCR – Large Property Managers	F2F Interviews (MRA101)	8	2	4	It was not possible to find a fifth manager that was willing to respond.
	Phone Interviews (MRA102)		3	0	
CL & CHCR – YEC & YECL Key Account Managers	F2F Meeting (MRA11)	TBD	2	0	Was cancelled because there is no account manager.
CHCR – HVAC or Control Contractors	F2F Interviews (MRA121)	5	1	3	Response rate was slightly lower than expected.
	Phone Interviews (MRA122)		3	0	
CHCR – HVAC or Control Engineer/Designer	F2F Interviews (MRA13)	5	2	2	Nothing to report.
RR, CL & CHCR – Multiple Key Stakeholders	F2F Interviews (MRA14)	N/A	7	6	We were not able to talk to the Contractors Association.

Where F2F means face-to-face, RR means Residential Retail, CL means Commercial Lighting, HVAC means Heating, Ventilation and Air-Conditioning, CHCR means Commercial HVAC and Control Retrofit, E/L means Electrical and/or Lighting, TBD means To Be Determined and MRA means Market Research Activity.

4. Details on the Market Research Activities

This section describes the research activities that were designed and undertaken. The discussion presents a description of each research activity, the justification for using the selected strategy, and the approach to recruiting respondents.

MRA01 RR – Retail Store Manager Interviews

Short description	Face to face, directed, in-depth interviews with Retail Store Managers (approx. 1h)
Justification of the choice of activity	Population size is small. Their views are very important because we envision working with them as trade allies. Managers will be able to provide meaningful market insights on their sales and the behavior of their customers. Therefore, it was important to use an in-depth and explorative method such as face-to-face interviews.
Identification of participants, notification and recruitment	YEC and/or YECL did not have contact information. Therefore, it was necessary to send a notification letter and then conduct cold calls to identify potential respondents. Eligible respondents needed to be in charge of the purchase and stocking of selected store(s). A representative from YEC called the stores directly, inquired about the managers, established the individual's eligibility, and attempted to schedule a telphone meeting.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All the respondents were sent the interview guides before the interview. ICF Marbek staff led the interviews, with a YEC staff member participating in most interviews.

MRA02 RR – Mystery Shoppers

Short description	30-minute visit to stores such as Canadian Tire, Walmart, Home Hardware, etc. The protocol was: 1) Go to store and make observations on the shelving displays of the selected equipment, most likely lighting equipment and appliances; 2) Make notes on merchandizing activities and promotions; 3) Talk to a member of the floor staff responsible for a specific display (same as for 1), ask a short set of questions, and note the answers.
Justification of the choice of activity	Get unbiased market intelligence through observations rather than relying on the views of the store managers. Reduce the number of questions to the store managers and thus the duration of the interviews by getting the information at the source. Relatively easy to set up.
Identification of participants, notification and recruitment	YEC and YECL staff identified the stores.
Approach to data collection	ICF Marbek created a mystery shopper protocol that contained the scenarios, the questions and, a template to write notes and observations. There were no recording, transcripts, and photos. ICF Marbek briefed the mystery shoppers and aggregated the notes.

MRA03 RR – Retail Intercepts

Short description	15-minute in-store in-person interview with targeted shoppers.
Justification of the choice of activity	We wanted to understand the decision-making process of someone who is buying an incandescent light bulb/or non-ESTAR appliance, on the spot and at the moment when the experience was fresh in their mind. We envisioned that the potential program activities and tactics would include rebate and Point-of-Purchase materials. Therefore information from retail intercepts would be very valuable. A number of the candidate items for inclusion in the retail program are purchased infrequently. That means that general polling would randomly select a lot of people who haven't thought about these decisions for several years. Retail intercepts would not have to deal with all those "not applicables" because it would catch people right after they made the choice we are interested in.
Identification of participants, notification and recruitment	The interviews were coordinated with the store manager. The interviewers wore a YEC badge. There was one interviewer on site. The retail intercepts happened on the weekend. A short "notification letter" was prepared to share with the store staff. In the first approach employed, the interviewer identified him/herself to the staff at the cash registry. The staff was advised to buzz the interviewer if certain items were purchased, such as: 1) incandescent, CFL or LED light bulb(s); or, 2) a large appliance (E-STAR or not) such as a refrigerator, freezer, cloth washer, hot water tank, or dishwasher. The interviewer could then solicit the customer. A table and a few chairs provided a venue to conduct the interview. To boost the response rate, the interviewer had small gifts, which were the same coupons that were used by YECL in the Arctic Winter Game. The respondent used the "Price-is-Right" machine in place of a dice to earn a gift. It was found that this approach was ineffective as people rushed out without talking to the interviewer. A second approach was then used that was more effective. In this case, the interviewer intercepted the shoppers directly in the aisle e.g., in the lighting equipment section of the store. People were more willing to respond at that moment.
Approach to data collection	ICF Marbek created a retail intercept guide containing information such as, how to do the following: coordinate with the store manager; brief the staff at the cash registry; set up (chairs and table) and wear visual identification tags (YEC and/or YECL logos); approach customers and distribute gifts, including introduction script, questions and reporting. The results were documented using a questionnaire with ticked boxes.

MRA05 RR & CL – Independent Lighting Retailers Interviews

Short description	45-minute in-depth partially-directed interview(s). Independent lighting retailers are typically very small businesses (often one person), who import lighting equipment (lamps, fixtures) directly from the manufacturers and sell them directly to residential and commercial clients. They have very little infrastructure and overhead; many operate from their basement. Based on our observations, this group appears to sell premium quality equipment.
Justification of the choice of activity	It was assumed that the population of independent retailers was approximately 5 to 10. For such a small population, we believed that in-depth interviews would be the most effective means to obtain the needed market information. We knew little about these retailers. We suspected they might have a market share that is more significant in the Yukon than in other jurisdictions. We believed that we needed to maintain flexibility for improvisation during the interview. Hence, a *partially-directed* interview style was employed because: 1) The individuals and their market roles were not clearly known; 2) It was difficult to predict what the most useful discussion topics were going to be.
Identification of participants, notification and recruitment	The retailers were identified through word-of-mouth and from the contact network of YEC and YECL staff.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues.

MRA06 CL – E/L Distributor Interviews

Short description	Electrical equipment distributors and specialized lighting distributors were consulted through 60-minute telephone and in-person, directed interviews. YEC or ICF Marbek staff conducted the interviews.
Justification of the choice of activity	It was known beforehand that the population of distributors in the Yukon would be small (approximately 3-5 firms), and therefore that the sample size would also be small. Also, some distributors operating in the Yukon are located outside the territory; consequently, it was anticipated that many interviews would be conducted by telephone. Since distributors are key actors in the supply chain, it was important to use an in-depth and explorative method. A "directed-interview" format was employed.
Identification of participants, notification and recruitment	YEC or YECL had information on the two distributors that have a local branch. ICF Marbek looked for other distributors through existing relationships and prior work in this sector. ICF Marbek sent an email to the non-resident distributors to ask them for an appropriate Yukon contact. There was one response; the identified contact was located in the Northwest Territories.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guides before the interview.

MRA07 CL – Manufacturer Agent Interview(s)

Short description	60-minute in-depth directed interview(s), primarily via telephone by YEC and ICF Marbek staff.
Justification of the choice of activity	Lamp manufacturer agents (or reps) have a valuable perspective on the lighting sector in the Yukon. Therefore, it was important to use an in-depth and explorative method. Because they are located outside of the territory, telephone interviews were employed. The nature and role of these organizations is relatively well known, and thus we used a "directed-interview" format.
Identification of participants, notification and recruitment	Manufacturer agents or representatives were identified through interviews with distributors and lighting designers. They are based in B.C. and Alberta, not in the Yukon. ICF Marbek cold-called the individuals and scheduled the interviews from Ottawa.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guides before the interview.

MRA08 CL – Lighting Designers and/or Engineer Interview(s)

Short description	Lighting designers were consulted through in-person directed interviews.
Justification of the choice of activity	It was known beforehand that the population of lighting designers in Yukon would be small (approximately 1 to 5 individuals), and therefore that the sample size would also be small. Since designers are key actors in the supply chain, it was important to use an in-depth and explorative method such as face-to-face interviews.
Identification of participants, notification and recruitment	YEC staff knew one lighting designer and called them directly to book the appointment.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. The respondent was sent the interview guide before the interview.

MRA09 CL – Electrical Contractors Interviews

Short description	Electrical contractors were consulted through a 30-minute directed telephone interview.
Justification of the choice of activity	Contractors are important market influencers but are difficult to engage as they are very busy and often out of their office; hence, a telephone interview was preferred. The number of contractors was estimated to be approximately 20 to 50. Therefore we needed a larger sample size but also recognized that many may not be available to participate in the interview.
Identification of participants, notification and recruitment	YEC staff located electrical contractors through web searches and the Yellow Pages. Significant effort was required to convince the electrical contractors to participate. A formal notification letter was sent by YEC and YECL, followed by a cold-call from YEC staff.
Approach to data collection	ICF Marbek created a questionnaire based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA10 CL & CHCR – Large Property Managers Interviews

Short description	Large Property Managers were consulted via a 30 to 60 minute in-depth telephone or in-person interview.
Justification of the choice of activity	Since large Property Managers are important market influencers, we used an in-depth and explorative method.
Identification of participants, notification and recruitment	We identified relevant property managers through existing YEC & YECL relationships. Commercial key accounts were particularly targeted. YEC & YECL key account managers were able to provide the contact information. Interviews were arranged by YEC personnel.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA12 CHCR – HVAC or Control Contractors Interviews

Short description	We consulted with the HVAC and Control Contractors through a combination of telephone and in-person interviews.
Justification of the choice of activity	HVAC and Control Contractors are important influencers in the supply chain for HVAC and control retrofits, as it was assumed that very few of these retrofits actually involve an extensive design team. Consequently, it was important to employ an in-depth and explorative method such as interviews.
Identification of participants, notification and recruitment	We identified HVAC and control contractors through existing ICF Marbek relationships, including CPR workshop participants. Additional contractors were identified through sources such as the electrical contractors association, the mechanical contractors association, NRCan service provider lists, the Yellow Pages, Google searches, etc. YEC sent a notification email to the targeted individuals. Then YEC staff followed-up by telephone to set up a meeting.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA13 CHCR – HVAC or Control Engineer/Designer Interview(s)

Short description	HVAC and Control Engineers/Designers were consulted through in-person directed interview(s).
Justification of the choice of activity	It was known beforehand that the population of HVAC and Control Engineers/Designers in the Yukon would be small (approximately 1 to 5 individuals) and therefore the attainable sample size would also be small. HVAC designers are important potential program partners because they could undertake direct customer engagement, act as RCx agent or energy auditor and/or develop projects to be financed by a potential Utilities program.
Identification of participants, notification and recruitment	YEC staff called local engineering firms to identify the designers among their staff. A representative of YEC called the individuals to schedule the interviews.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guide before the interview.

MRA14 RR, CL & CHCR – Interviews with Multiple Key Stakeholders

Short description	60 minute undirected in-person interviews with Stakeholders.
Justification of the choice of activity	Many of the stakeholders represent potential program implementation partners. We wanted to know the role/mission/core business of each of the organizations, as well as their areas of particular strength/interest. Each interview was tailored to the specific organization based on available information. Therefore an "*undirected* interview" approach was employed.
Identification of participants, notification and recruitment	YEC provided the necessary contact information and arranged the meetings. The relevant stakeholders included: • Whitehorse Chamber of Commerce, • Association of Professional Engineers of Yukon Territory (APEY), • Yukon College, • Yukon Technology Innovation Centre, • Consulting Engineers of Yukon, Chamber of Mine, • and/or Yukon Contractors Association Meetings were in-person as much as possible. A representative of YEC made the telephone call to plan the meeting. Many meetings were planned during the week of April 16, 2012, when a representative of ICF Marbek was in Whitehorse.
Approach to data collection	A short description of the interview's purpose was sent by email to each participant. A short and flexible meeting agenda was created at the beginning of each meeting.

MRA15 RR – Interviews with New Condominium and Townhouse Developers

Short description	60 minute undirected in-person interviews with developers.
Justification of the choice of activity	Much of the current new home construction in the Whitehorse area is townhouse and condominium developments. These units are generally sold with lighting and appliances already installed. As these developers are making choices on a large volume of lighting and appliances, they represent a large part of the residential retail market. Given the tight real estate market, customers have less influence on these decisions than they could have in a more competitive market. The number of developers is fairly small. They can provide meaningful market insights on their current practices and the behavior of their customers. Therefore it was important to use an in-depth and explorative method such as in-person interviews.
Identification of participants, notification and recruitment	YECL provided names of the developers that are setting up accounts. Meetings were in-person as much as possible. A representative of YEC set up the meetings.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA16 RR – Interviews with Residential Rental Property Managers and Landlords

Short description	60 minute undirected in-person interviews with property managers and landlords.
Justification of the choice of activity	Rental units make up a large percentage of the residences in Whitehorse. The decisions regarding types of lighting and appliances are generally made by the property managers or landlords. As these managers and landlords make choices on a large volume of lighting and appliances, they represent a large part of the residential retail market. Given the tight real estate market, renters have less influence on these decisions than they could have in a more competitive market. The number of managers and landlords is fairly small. They can provide meaningful market insights on market barriers and the behavior of their customers. Therefore it was important to use an in-depth and explorative method such as in-person interviews.
Identification of participants, notification and recruitment	YECL provided names of the landlords. Meetings were in-person as much as possible. A representative of YEC set up the meetings.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

5. Table of Researchable Issues

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
Residential Retail Program																	
Research question #1: RR - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
RR101	Demographics	Actors			X												
RR102	Purchase: EE equipment or non-EE equipment	Actors			X												
RR103	Firmographics	Actors	X			X	X									X	X
RR105	Challenges currently faced by the organisation	Actors	X			X	X									X	X
RR107	Management framework/Org Chart	Actors	X													X	X
RR140	Missing Market Actors	Actors	X			X	X									X	
Research question #2: RR - How do actors interact with each other in the absence of a program?																	
RR104	Major customer segments	Structure	X			X	X									X	X
RR106	Major suppliers	Structure	X				X									X	X
RR108	Best media outlets to reach your businesses	Structure	X	X	X	X	X									X	X
RR109	Best media outlets used to reach out to clients	Structure	X			X	X									X	X
RR110	Best source(s) of information on best practices	Structure	X	X	X		X									X	X
RR111	Clients' purchase drivers	Structure	X	X	X	X	X									X	X
RR115	Reasons for making special efforts wrt EE	Structure	X	X		X	X									X	X
RR117	Drivers of salesforce	Structure	X		X												
RR130	Main means to train salesforce	Structure	X													X	
RR118	Organisation's purchase/stocking drivers	Structure	X													X	X
RR128	Program activity most likely to partake in	Structure	X		X		X									X	X
RR150	Linear shelf space of EE products vs baseline	Structure		X													
RR151	Promo on retail price of EE products vs baseline	Structure		X													
RR152	Merchandising activities of EE products vs baseline	Structure		X													
RR163	How is a supplier selected?	Structure	X														
Research question #3: RR - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
RR112	Clients' purchase barriers	Barriers	X	X	X		X									X	X
RR113	Visibility (shelf space) of EE equipment as compared with others	Barriers	X		X												
RR114	Ease of getting information on EE of product in the store	Barriers		X	X												
RR116	Reasons for NOT making more efforts wrt EE	Barriers	X	X		X	X									X	X
RR119	Perception of applicability of the information available	Barriers	X	X	X	X	X									X	
RR120	Issues with availability of equipment and services	Barriers	X			X	X										X

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
RR121	Technical issues with EE equipment and services	Barriers	X			X	X										
RR122	How good at promoting EE are - Retailers in general?	Barriers				X	X										X
RR123	How good at promoting EE are - Retail store managers?	Barriers		X													
RR124	How good at promoting EE are - Suppliers?	Barriers	X														X
RR125	How good at promoting EE are - Property Managers & landlords?	Barriers	X			X	X									X	
RR155	How good at promoting EE are - Contractors?	Barriers	X			X	X										X
RR126	Credibility of YEC wrt EE and DSM	Barriers	X	X	X	X	X									X	X
RR127	Credibility of the YECL wrt EE and DSM	Barriers	X	X	X	X	X									X	X
RR153	Credibility of YG organizations such as ESC and Yukon Housing	*Barriers*														X	X
RR154	Out-of-stock status on EE product vs Baseline (yes/no)	Barriers		X													
RR160	Extent of the double-agent barrier	Barriers			X											X	X
RR161	Overall satisfaction re: existing Yukon program - Good	Barriers			X												X
RR162	Overall satisfaction re: existing Yukon program - EcoEnergy	Barriers			X												X
Commercial Lighting Program																	
Research question #1: CL - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
CL201	Firmographics	Actors						X	X	X	X	X					
CL203	Challenges currently faced by the organisation	Actors						X	X	X	X	X					
CL205	Management framework/Org Chart	Actors						X		X		X					
CL206	Find the lighting designers	Actors						X	X								
CL240	Missing market actors	Actors						X	X	X							
Research question #2: CL - How do actors interact with each other in the absence of a program?																	
CL202	Major customer segments	Structure						X	X	X	X	X					
CL204	Major suppliers	Structure						X			X						
CL207	Best media outlets to reach your businesses	Structure						X	X	X	X	X					
CL208	Best media outlets used to reach out to clients	Structure					X	X	X	X	X						
CL209	Best source(s) of information on best practices	Structure						X	X	X	X						
CL210	Clients' purchase drivers	Structure					X	X	X	X	X	X					
CL212	Reasons for making special efforts wrt EE	Structure						X	X	X	X	X					
CL214	Drivers of salesforce	Structure						X									
CL240	Major means to train salesforce	Structure						X									
CL215	Organisation's purchase/stocking drivers	Structure						X				X					
CL227	Program activity most likely to partake in	Structure						X	X	X		X					
CL241	Occurrence of the electrical contractor to decide (or exert heavy influence) on what equipment to install	Structure								X	X	X					

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
Research question #3: CL - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
CL211	Clients' purchase barriers	Barriers					X	X	X	X	X						
CL213	Reasons for NOT making more efforts wrt EE	Barriers						X	X	X	X	X					
CL216	Perception of Applicability of the information available	Barriers					X	X		X							
CL217	Issues with availability of equipment and services	Barriers					X	X	X	X	X	X					
CL218	Technical issues with EE equipment and services	Barriers					X	X	X	X	X						
CL219	How good at promoting EE are - Lighting Distributors?	Barriers					X		X	X	X	X					
CL220	How good at promoting EE are - Independent Lighting Suppli	Barriers						X	X	X	X	X					
CL221	How good at promoting EE are - Lighting Designers?	Barriers					X	X	X		X	X					
CL222	How good at promoting EE are - Lighting manufacturers age	Barriers					X	X		X							
CL223	How good at promoting EE are - Electrical Contractors?	Barriers					X	X	X	X		X					
CL224	Current market penetration of certain EE-specific services	Barriers						X	X	X	X	X					
CL225	Credibility of YEC wrt EE and DSM	Barriers						X	X	X	X	X					
CL226	Credibility of the YECL wrt EE and DSM	Barriers						X	X	X	X	X					
CL242	Occurrence of the electrical contractors to substitute equipment after the design phase of the project	Barriers								X	X	X					
CL250	Credibility of YG organizations such as ESC and Yukon	*Barriers*															
Commercial HVAC & Control Retrofit Program																	
Research question #1: CH - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
CH301	Firmographics	Actors											X	X			
CH303	Challenges currently faced by the organisation	Actors											X	X			
CH304	Management framework/Org Chart	Actors											X				
CH306	Find the HVAC/Control designers	Actors										X	X				
CH307	Find the EE experts	Actors										X	X	X			
Research question #2: CH - How do actors interact with each other in the absence of a program?																	
CH302	Major customer segments	Structure											X	X			
CH308	Major suppliers	Structure										X	X				
CH309	Best media outlets to reach your businesses	Structure											X	X			
CH310	Best media outlets used to reach out to clients	Structure												X			
CH311	Best source(s) of information on best practices	Structure											X	X			
CH313	Reasons for making special efforts wrt EE	Structure											X	X			
CH322	Clients' purchase drivers	Structure											X	X			
CH327	Reasons for investing	Structure										X					
CH328	Program activity most likely to partake in	Structure										X	X	X			

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
CH342	Occurrence of the contractor to decide (or exert heavy influence) on what equipment to install	Structure										X	X	X			
Research question #3: CH - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
CH312	Reasons for NOT making more efforts wrt EE	Barriers											X	X			
CH314	Clients' purchase barriers	Barriers											X	X			
CH315	Issues with availability of equipment and services	Barriers										X	X	X			
CH316	Technical issues with EE equipment and services	Barriers											X	X			
CH317	How good at promoting EE are - HVAC/Control Engineers?	Barriers										X	X				
CH318	How good at promoting EE are - HVAC/Control Contractors?	Barriers										X		X			
CH340	How good at promoting EE are - Equipment Suppliers?	Barriers											X	X			
CH320	Reasons for not entering the EE business or using EE to boost sales	Barriers											X	X			
CH323	Reasons for not investing (more)	Barriers															
CH324	Extent of the double-agent barrier	Barriers										X	X	X			
CH325	Credibility of YEC wrt EE and DSM	Barriers											X	X			
CH326	Credibility of the YECL wrt EE and DSM	Barriers											X	X			
CH350	Credibility of YG organizations such as ESC and Yukon	*Barriers*															
CH341	Perception of Applicability of the information available	Barriers												X			
Research question #4: CH - Why is the current market penetration of EE services and equipment and what is the naturally-occuring trend?																	
CH319	Current market penetration of certain EE-specific services	Baseline										X	X	X			
CH321	Recent investment in EE?	Baseline										X					
Other Organizations and Stakeholders																	
Research question #1: RR, CL & CH - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
OO401	Mission and vision	Actors													X		
OO402	Existing conservation, sustainability, GHG reduction goals	Actors													X		
OO403	Challenges currently faced by the organisation	Actors													X		
OO404	General interest in EE	Actors													X		
OO405	Knowledge wrt EE	Actors													X		
OO406	Management framework/Org Chart	Actors													X		
OO407	Human resources	Actors													X		
OO408	Logistical resources (Office?, IT?)	Actors													X		
OO409	Size of membership or extend of visibility	Actors													X		
OO410	Media to the market that are being used	Actors													X		
OO411	Other resources (training materials?, methods?, data?)	Actors													X		

Saving energy your way

Survey results summary

Total No. of Surveys 449

Question #1 - USERS SHOULD LIMIT DEMAND BY USING ENERGY EFFICIENTLY

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
				75%	
39	10	9	56	335	449

Question #2 - DEVELOP EFFICIENCY PROGRAM - FUNDED BY CUSTOMERS

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
			39%		
35	26	58	177	153	449

Question #3 - DEVELOP EFFICIENCY PROGRAM - FUNDED BY UTILITIES & RESIDENTS

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
				42%	
33	32	48	147	189	449

Question #4 - MOST EFFECTIVE WAYS TO REDUCE ENERGY USE IN THE YUKON

PUBLIC EDUCATION

Most Effective	Somewhat Effective	Not Effective	No Answer	
52%				
232	169	16	32	449

PROGRAMS THAT HELP PUBLIC TAKE ENERGY EFFICIENT ACTIONS

Most Effective	Somewhat Effective	Not Effective	No Answer	
55%				
246	149	15	39	449

SUBSIDIZE PRODUCTS THAT REDUCE CONSUMPTION

Most Effective	Somewhat Effective	Not Effective	No Answer	
61%				
276	121	13	39	449

TIME OF USE INCENTIVES

Most Effective	Somewhat Effective	Not Effective	No Answer	
	35%			
120	155	132	42	449

BETTER ENERGY EFFICIENCY STANDARDS FOR NEW CONSTRUCTION

Most Effective	Somewhat Effective	Not Effective	No Answer	
65%				
290	108	18	33	449

HIGHER EFFICIENCY STANDARDS FOR NEW APPLIANCES

Most Effective	Somewhat Effective	Not Effective	No Answer	
67%				
299	103	12	35	449

Question #5 - MOST EFFECTIVE WAYFOR YOU TO REDUCE YOUR ELECTRICITY CONSUMPTION

PUBLIC EDUCATION				
Most Effective	Somewhat Effective	Not Effective	No Answer	
49%				
219	140	48	42	449

PROGRAMS THAT HELP PUBLIC TAKE ENERGY EFFICIENT ACTIONS				
Most Effective	Somewhat Effective	Not Effective	No Answer	
50%				
224	147	33	45	449

SUBSIDIZE PRODUCTS THAT REDUCE CONSUMPTION				
Most Effective	Somewhat Effective	Not Effective	No Answer	
67%				
302	88	20	39	449

TIME OF USE INCENTIVES				
Most Effective	Somewhat Effective	Not Effective	No Answer	
	31%			
128	138	130	53	449

Yukon Energy Corporation

Knowledge, Awareness and Opinion Research
Public and Stakeholder Survey Results
Research Report 2

Prepared by
Andrew Hume and Associates Ltd.
In association with Aasman Brand Communications

July 21, 2010

aasman
branding on purpose

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YUKON ENERGY CORPORATION
PUBLIC OPINION ONLINE SURVEY RESULTS – JUNE 2010

Introduction

A combination of telephone and online surveys were conducted with the public and community and business leaders in communities throughout the Yukon between June 2 – July 15, 2010.

The survey methods covered a range of questions on the Yukon Energy Corporation and energy related issues.

This report focuses on the results of two online surveys: an open public survey; and a targeted survey directed to community and business leaders. A report on the result of two telephone surveys of these same groups was filed previously and should be reviewed as complimentary findings to this report. A narrative summary of findings of the two telephone surveys is included in this report. Data from the two telephone surveys can be found in the previously filed report.

Both phone surveys were conducted prior to the launch of the public awareness campaign. The online surveys were conducted simultaneous with the campaign.

Participation in the public survey was promoted through an awareness campaign as well as on the Yukon Energy Corporation's website and an incentive was offered (pubic survey only) to enhance participation.

Research Goals

- To provide the Yukon Energy Corporation with current Knowledge, Awareness and Behaviour (KAB) among Yukon residents and business and community leaders toward the corporation and current and future energy needs.
- To build a renewed sense of trust and confidence among Yukon residents in the corporation supporting its vision of a clean energy future.

Research Objectives

- To establish baseline KAB data
- To effectively position the Yukon Energy Corporation and its vision for a clean energy future
- To inform public communications initiatives and campaign information and messaging undertaken by the Yukon Energy Corporation

Research Targets

To achieve a confidence level of 95% an overall target for all methodologies was 380 respondents. Research targets were surpassed.

• Public phone survey:	184
• Public online survey:	356
• Business and community leaders phone survey:	25
• Business and community leaders online survey:	41
TOTAL:	**606**

SECTION I
Summary of Public Telephone Survey Findings

Introduction

A telephone survey of 184 randomly selected Yukon residents in six communities was conducted between June 2 – 8, 2010.

- The majority of Yukon residents are aware the Yukon Energy Corporation is both a producer and distributor of power. However a significant number are not aware of the dual responsibility of the corporation with regard to the production and distribution of power as indicated by those who said the corporation was only a producer or only a distributor or did not know.

- A strong majority of respondents said it is important for them to know who produces and who distributes power.

- Hydro generated power is a clearly preferred alternative to diesel-generated power across all communities.

- There is a strong preference for the development of alternative energy sources. (For the purposes of the survey, 'alternative' was described as wind and geo-thermal).

  - Carmacks showed the highest level of support for alternative sources at 70% and residents of Marsh Lake showed the lowest support at 56%. In Whitehorse 65% of respondents identified alternative as a preferred source of power.

- When asked to think about the energy production and future needs, only slightly more than half (52%) of residents agreed that Yukon will not have enough energy to meet future needs. This was relatively consistent across all communities with the exception of Carmacks where 80% of respondents agree with this projection.

- A clear majority of respondents do not support diesel-generated power as a future energy source. The strongest support is for the development of new alternative energy sources followed by hydro.

- Yukon residents see large scale industry as the big driver in terms of creating the greatest demand for future energy needs followed by population growth (residential consumption). There was however a wide variance in response by different communities to this question ranging from a low of 50% (Dawson City) who see large industry as the biggest future power consumer, to 80% of respondents from Carmacks. In Whitehorse 52% of respondents said they saw large industry as creating the biggest energy demand.

- With reliability of the power supply, the majority of respondents feel there has been little change or it has improved over the past 12 months . Responses varied marginally by community with most in the 75%+ range in saying reliability has been better or the same.

- The majority of Yukon residents (78%) feel the reliability of power over the next five years is likely to remain unchanged or get better.

- Using Nunavaut/NWT and Edmonton for comparison, survey respondents were asked to indicate if they felt they paid more, less or the same for power. While Yukon residents feel they pay less or are not sure in relation to other northern residents they clearly feel they pay more than residents of Edmonton. Forty-four per cent (44%) of respondents said they were not sure.

- On the question of confidence in the Yukon Energy Corporation related to planning and developing clean energy sources to meet future needs, 58% said they had confidence in the corporation. The level of confidence ranged from a low of 30% in Haines Junction to a high of 80% in Carmacks. In Whitehorse 62% said they have confidence in the corporation.

- On the question of Yukoners assuming more personal responsibility toward energy conservation, 89% are in agreement.

- An equally high number (87%) of respondents agreed with a planning approach that would see new alternative energy sources developed in conjunction with hydro development to meet future needs.

- A strong majority (88%) reinforced their support for alternative and hydro by saying the Yukon needs to move away from diesel-generated power. Support for moving away from diesel-generated power ranged from a low of 70% in Haines Junction to a high of 90% in Whitehorse and Dawson City.

- Almost half (49%) of respondents were 51 years or older with over a one-third (37%) in the 31 to 50 year age group. The majority of respondents were also longer-term residents with 59% indicating 20 or more years of residency. Gender of respondents was relatively evenly divided.

- Sixty percent (60%) of respondents were surveyed in Whitehorse with 25 residents in Marsh Lake and Dawson City participating in the survey. For the smaller communities of Haines Junction and Carmacks 10 phone surveys were done in each community. In Teslin four surveys were conducted.

    - Note: It is important to note that the sample size in communities outside Whitehorse is not significant enough from which any conclusions can be drawn with any degree of confidence at an individual community level. The data indicated on a community-basis for some questions in this report is provided as a point of interest only and cannot be considered statistically significant unto itself.

SECTION II
Summary of Community and Business Leaders Telephone Survey Findings

Introduction
A telephone survey of 25 business and community leaders representing a cross sample of businesses, Yukon-wide associations and local community leaders was conducted between June 4 – 11, 2010.

- Yukon business and community leaders indicate a high degree of confidence (88%) in the Yukon Energy Corporations' assessment that new energy sources will be needed within the next five years in order to meet future demands.

- Consistent with the public phone survey, business and community leaders believe large industry will be a primary driver in future energy demands and indicate a strong preference for alternative energy followed by hydro development. Support for diesel-generated power is very low.

- Approximately one-third (32%) of business and community leaders feel energy reliability worsened over the past 12 months as compared to about 18% of public survey respondents while two thirds (66%) said reliability was the same or better .

- In terms of expected reliability over the next five years, business and community leaders feel more confident with almost half (45%) expecting reliability to improve and only 16% expecting reliability to get worse and over one-quarter (28%) expecting no change.

- Over three-quarters (76%) of business and community leaders feel Yukon businesses need to do more toward energy conservation. While this is a strong indicator that businesses feel the need to assume greater responsibility for conservation, the public's sense of personal responsibility is much higher at 89%.

    - Comments related to this question indicate that conservations is a 'shared responsibility' across all sectors.

- There is a high degree of support (84%) among business and community leaders for the development of alternative energy sources in combination with hydro. Alternative energy also received strong support from the general public.

- Also consistent with the public's view, business and community leaders strongly believe that moving away from a reliance on diesel-generated power is the right goal for the Yukon Energy Corporation to be pursuing.

- Additional comments suggested that multiple alternative sources need to be further explored including things like bio-fuels and waste-energy in addition to hydro, wind and geo-thermal and natural gas should also considered. Some suggest the corporation lacks creativity with respect to new clean energy sources and opportunities.

- While a strong majority (84%) believe the Yukon Energy Corporation should be developing clean energy sources, just over half (56%) of business and community leaders have confidence in the corporation's ability to effectively plan and develop clean energy.

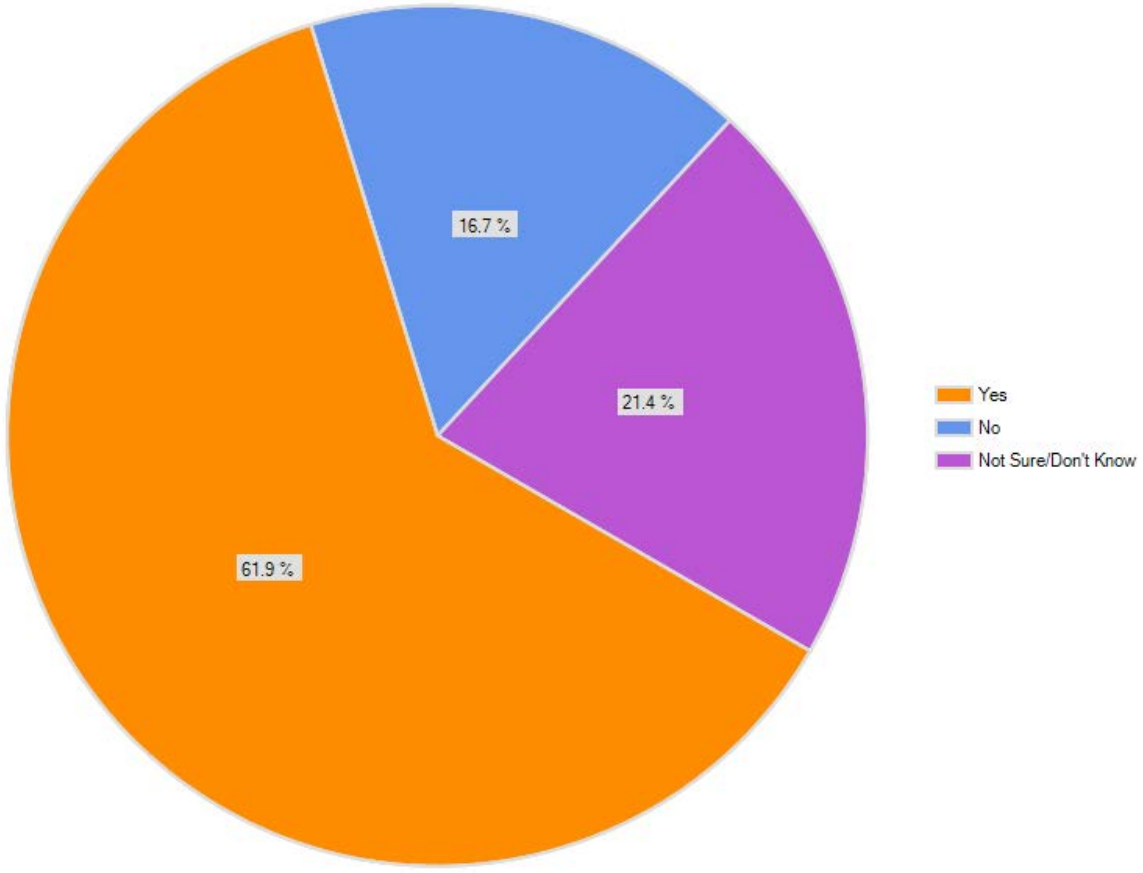
Additional comments included:

- Political influence and interference with the Yukon energy sector affects productivity and the ability to plan effectively. (Several mentions)
- Responding to external opposition and special interest groups interferes with effective planning.
- Years of opportunity to develop new clean energy sources have yielded little results.
- Reliability and cost need to be considered when developing alternative energy sources.
- Investment needs to be made in Yukon's power distribution system.
- Open up power generation to enable third parties to be become involved.
- The corporation needs to do more public consultation (this survey was a good start).
- Lack of a strategic plan and cost-benefit analysis.
- Lack of talk related to encouraging energy conservation.
- Important to plan and develop now to meet future needs and not get caught energy short. (Yukon Energy Corporation appears to be doing a good job projecting what future needs will be).
- More communication is needed on energy issues and options.

SECTION III
Findings from Community and Business Leaders Online Survey

Introduction
An online survey of 41 community and business leaders was conducted between July 7 – 15, 2010 representing individual businesses and organizations, Yukon-wide associations and local community leaders.

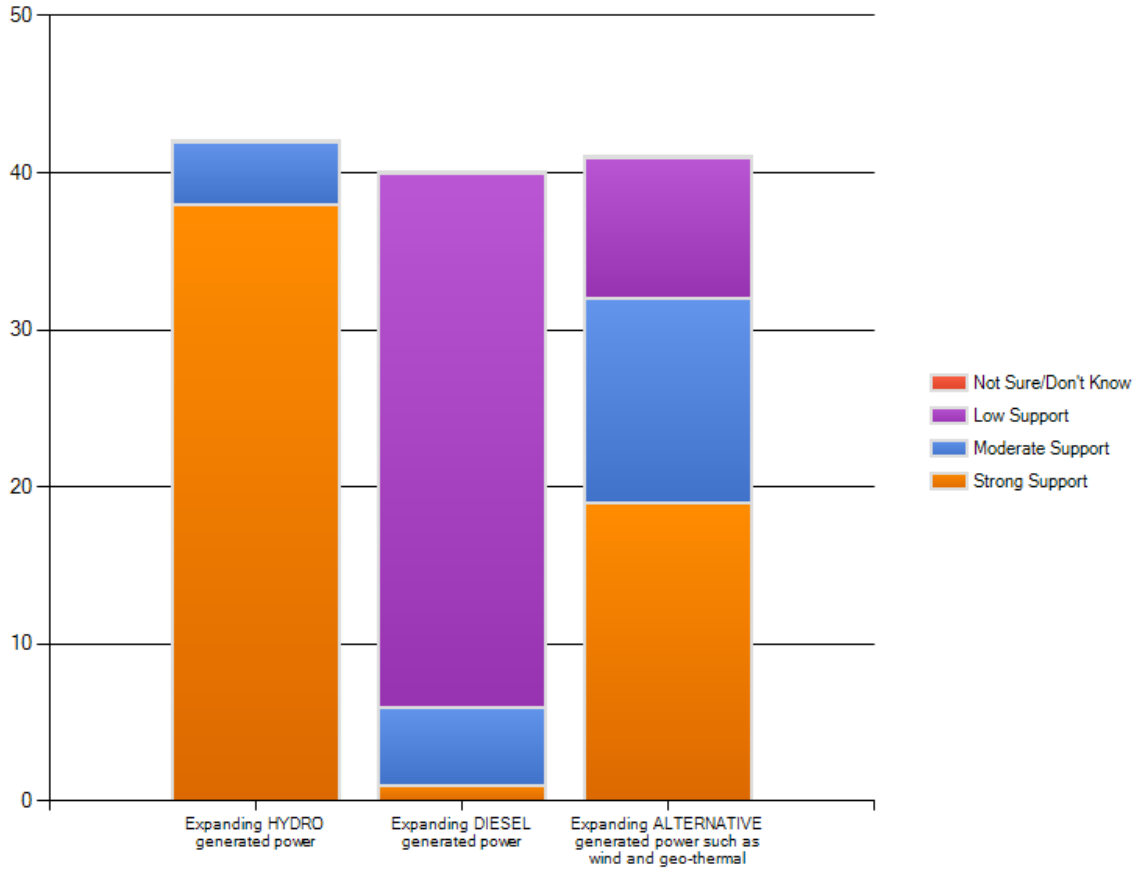
1. The Yukon Energy Corporation has identified the need for new sources of energy within the next five years to meet near future anticipated demands. Do you have confidence with this assessment?



Results show a 62% confidence level in the Yukon Energy Corporations' assessment of future energy needs with almost one-quarter (21%) of respondents unsure of their confidence. This reflects a statistically significant lower level of confidence than the telephone survey where 88% of respondents indicated a high degree of confidence in the corporation's future energy needs assessment.

The difference may be related to a greater level of comfort of anonymity with an online survey.

2. What level of support do you give each of the following power generation options?

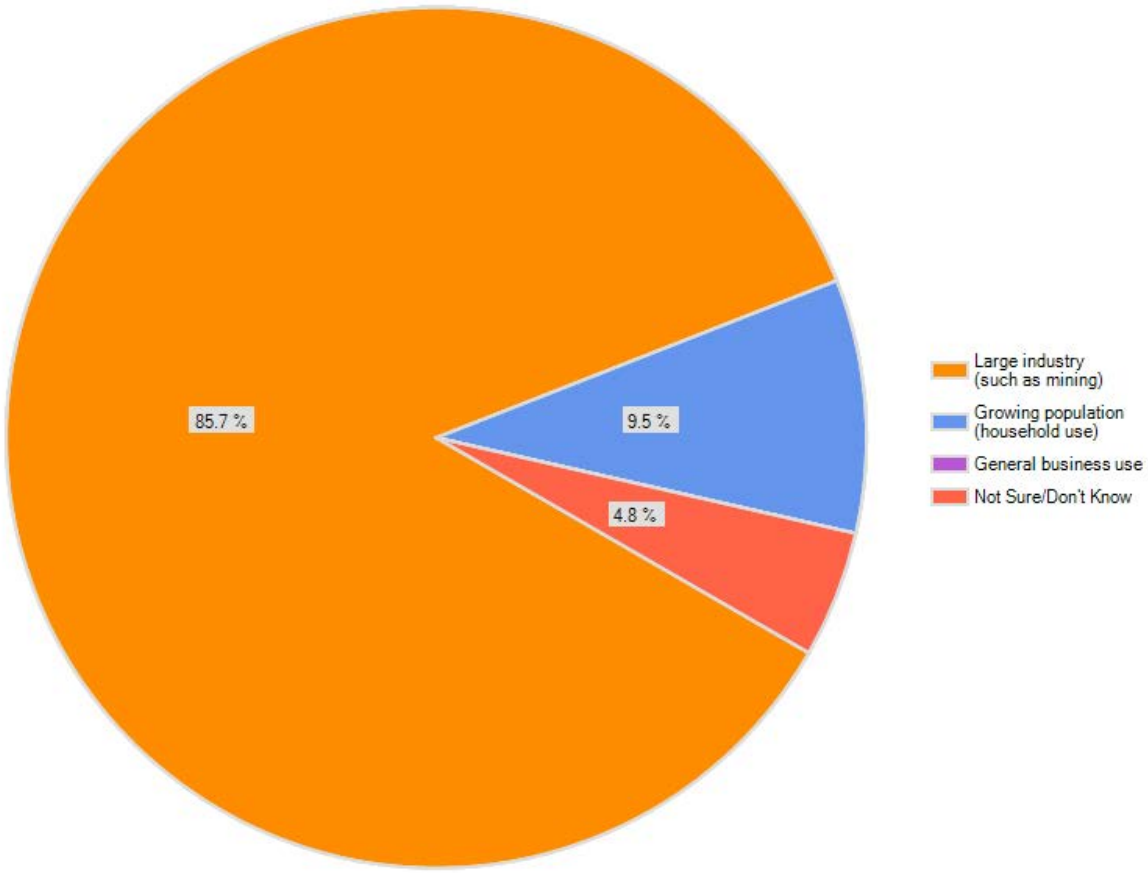


The online survey shows that business and community leaders have the strongest support (90%) for expanding hydro power followed by alternative generated power with 46% strong support. This differs from the community leaders phone survey which gave the expansion of alternative energy the strongest support followed by hydro sources.

The difference between the phone and online survey results may be related to an ideal preference reflected in the phone survey versus a more pragmatic view of what is realistically achievable as indicated by the online survey. Online surveys allow respondents more time to contemplate their view.

Phone surveys can include a degree of bias with respondents responding in what they perceive as the most politically or socially correct way, where online surveys allow for a greater sense of anonymity. Phone surveys also indicate 'top-of-mind' response whereas online surveys provide greater reflection time on a question. It is important therefore to consider both methodologies when assessing the data.

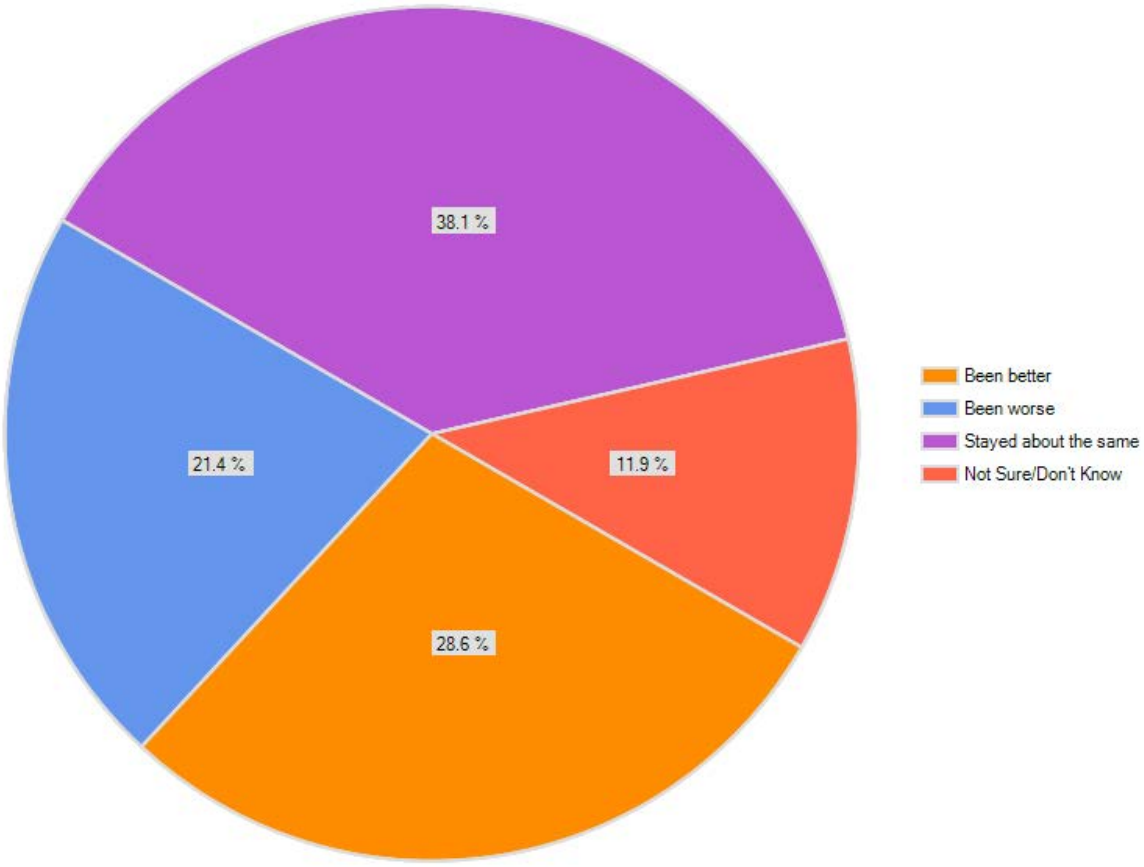
3. Which of the following will create the SINGLE GREATEST DEMAND on Yukon's future energy needs?



Both the online and phone surveys show community leaders believe large industry will create the greatest demand on future energy needs, however more respondents to the phone survey were unsure on this question than those who responded to the online survey.

- Phone Survey: 20% unsure
- Online Survey: 5% unsure

4. Over the past 12 months, has reliability in the supply of power:



On the question of past energy reliability, two-thirds (66%) of respondents to both the phone and online surveys said their power supply had remained the same or been better over the past 12 months.

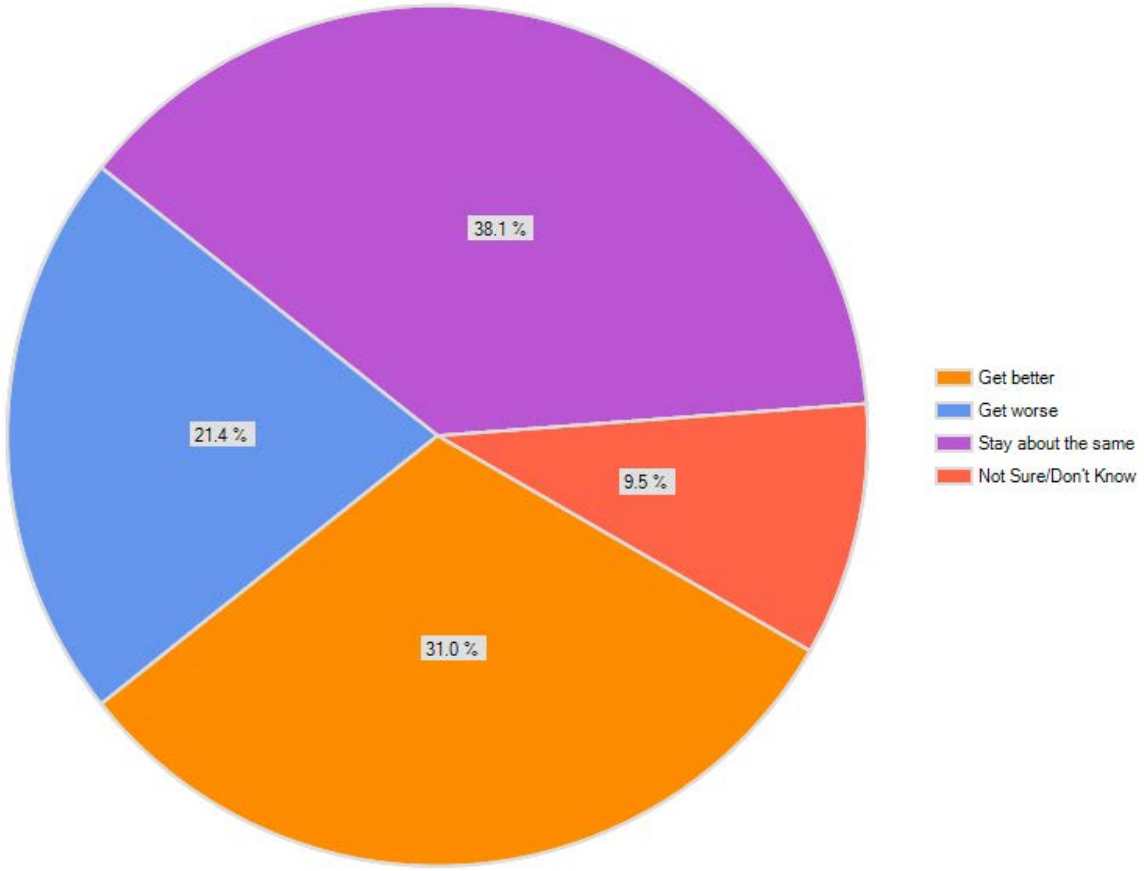
Note: The survey provided two 'confidence' indicators:

- One that relates to the corporation's ability to effectively plan and develop 'clean energy sources' to meet future needs; and
- One that relates to the provision of a stable or improved supply of energy in the future.

Q 5 (following page) relates to the later issue (stay the same or get better over the next 5 years) and shows a higher confidence level (68%) as opposed to Q 9 which focuses on confidence relative to the development of 'clean energy' sources to which 46% said they had confidence in the corporation's ability.

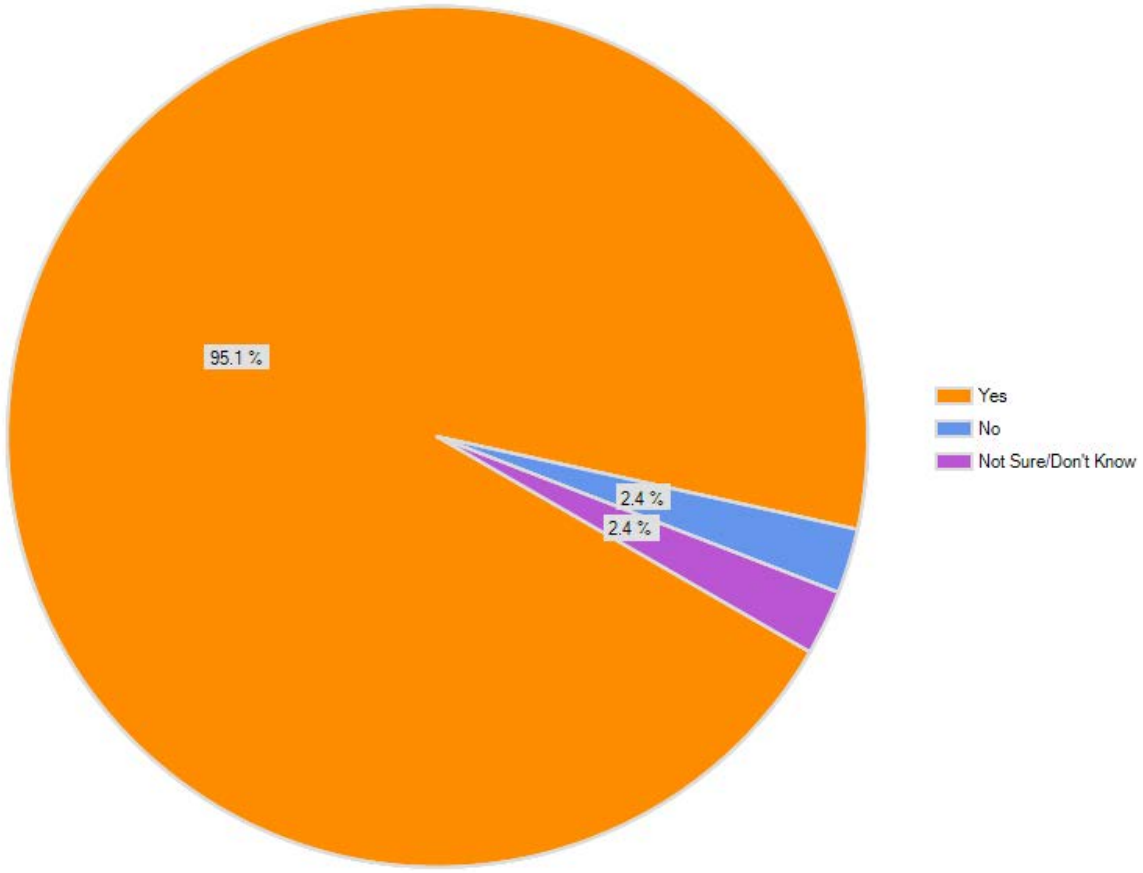
It should be further noted however that 20% of respondents to Q 9 also indicated they "did not know/not sure" about their level of confidence indicating an important margin for improvement in the overall confidence level in relation to planning a clean energy future.

5. In the next 5 years, do you expect the reliability of power to:



Thinking about anticipated energy reliability over the next five years an equal number of respondents to both survey methods (69%) expect the energy supply to remain the same or get better while a slightly higher percentage of online survey respondents versus phone respondents anticipated energy reliability would worsen (22% vs 16% respectively). An equal number from both survey methods (12%) indicated they are not sure about the future in terms of energy reliability.

6. Should business and industrial energy users be developing plans to use better energy conservation technologies, equipment and operational practices to help reduce demand?

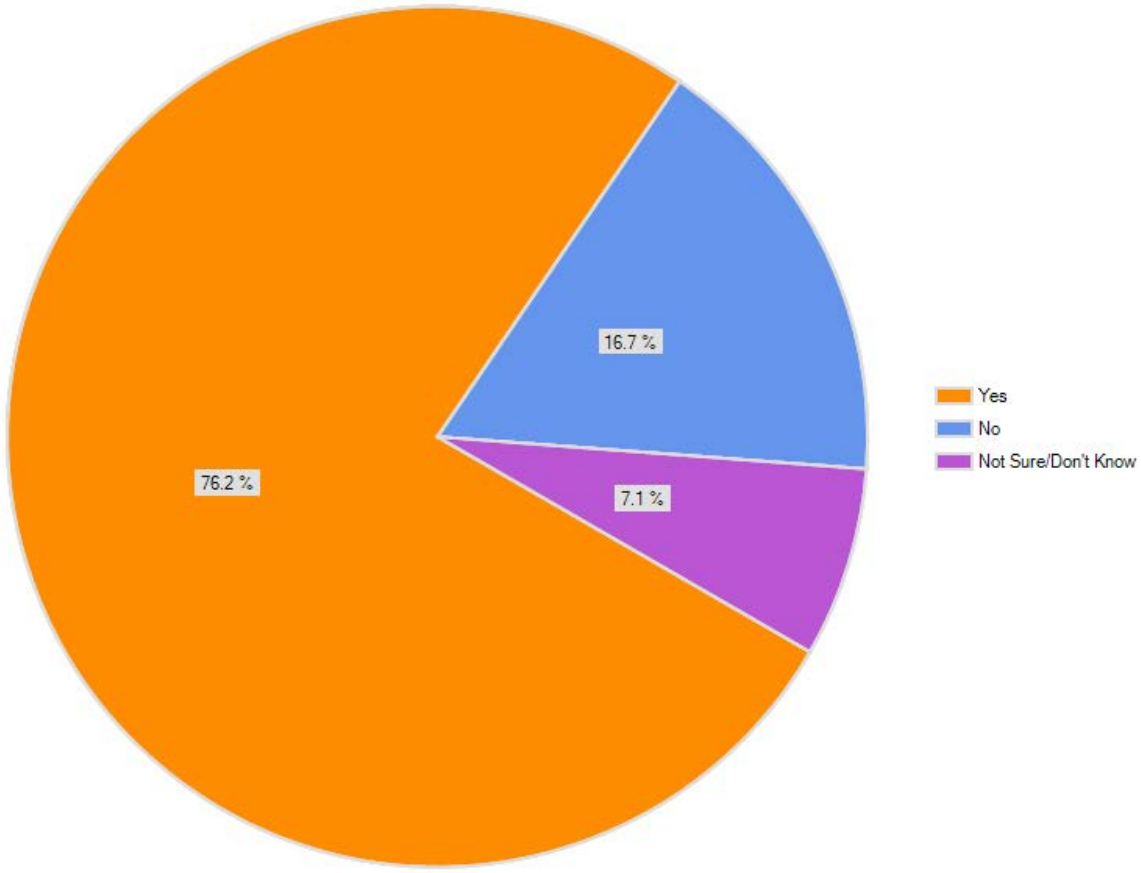


Both survey methods (phone and online) show a high degree of a sense of responsibility among business and community leaders with regard to the need for business and industry to do more toward energy conservation (95% online vs 76% phone).

The combined level of agreement on this issue between both survey methods shows strong support for the need for business and industry to develop plans for better energy conservation.

This high degree of awareness and acknowledgement of responsibility will be helpful should the Yukon Energy Corporation consider a future energy conservation program that requires the support and engagement of industry, business and community leaders.

7. Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?

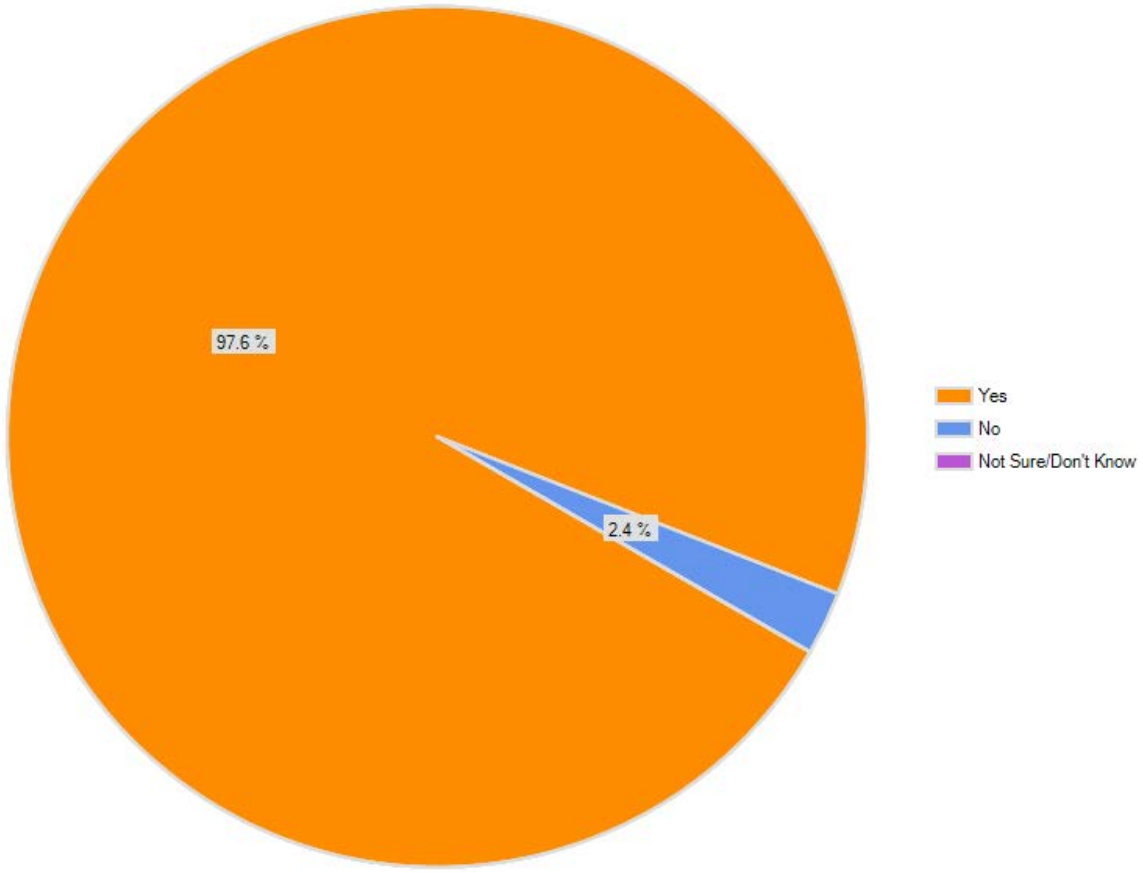


Consistent with the high degree of support for energy conservation measures, community and business leaders are also very supportive of continuing to develop clean energy sources in combination with new hydro sources.

The phone and online surveys showed 84% and 76% support respectively for developing new clean energy sources (described as wind and geo-thermal).

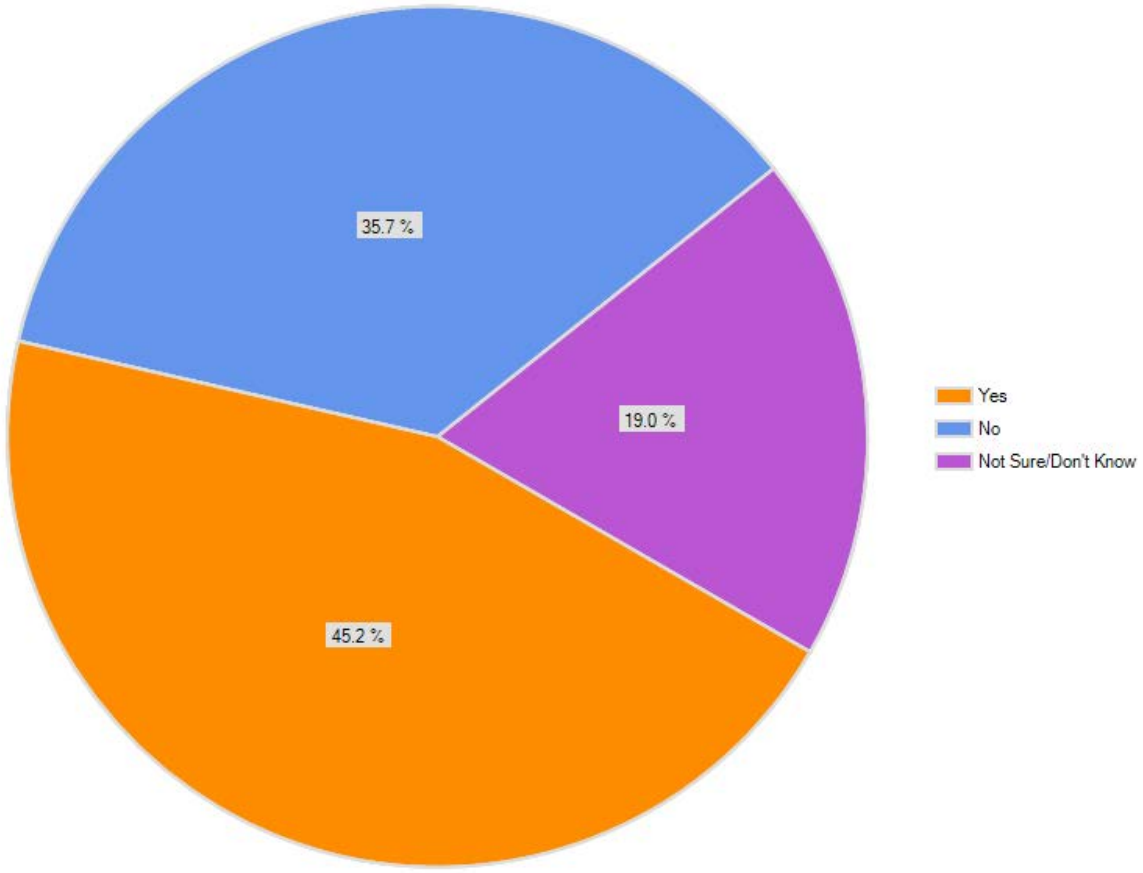
Note: Open comments collected through the survey suggest some felt the description of “wind and geo-thermal” was too narrow to represent alternative energy.

8. Is moving away from a reliance on diesel-generated power the right thing to do?



The view that Yukon should be moving away from the use of diesel-generated power is consistent between community leaders and the public. Several comments from community and business leaders however, recognize the important role diesel-generated power plays in smaller communities and as a back-up system

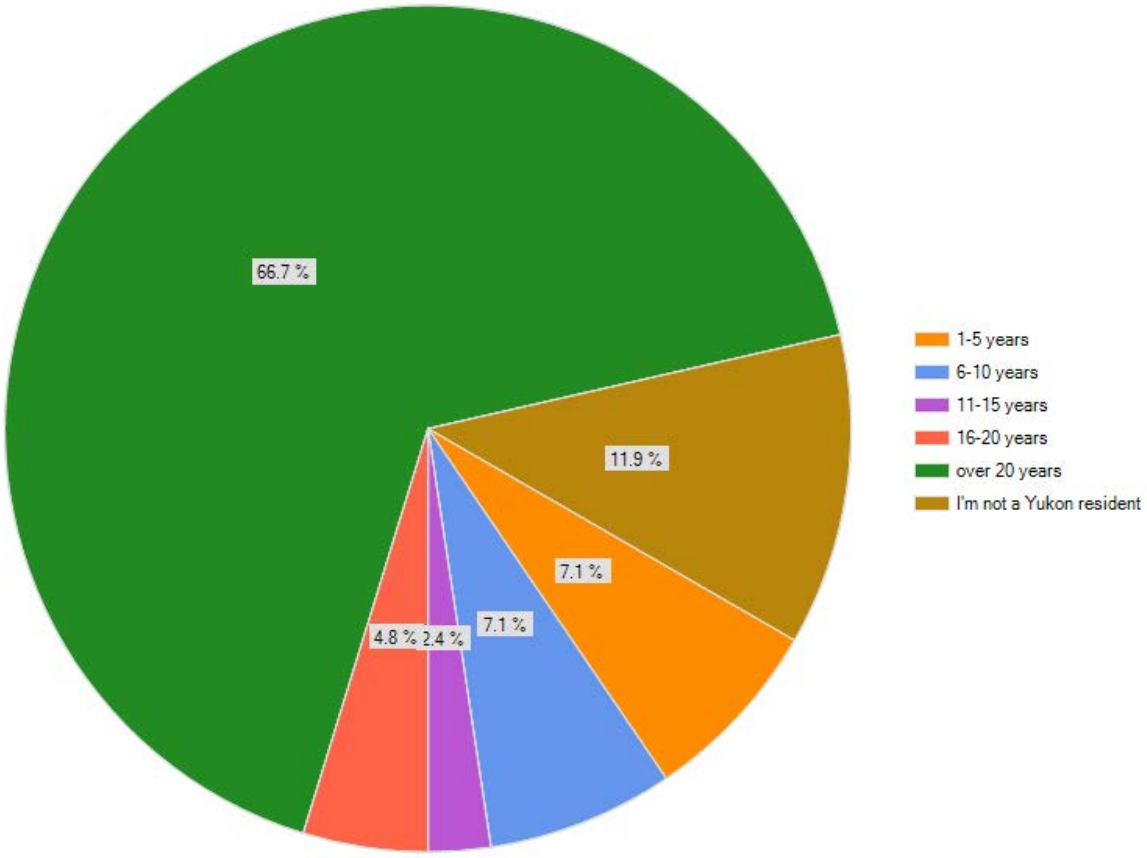
9. Do you have confidence in the Yukon Energy Corporation to plan and develop clean energy sources to meet future demands?



While community and business leaders support the development of clean energy sources, less than half of those surveyed (45%) say they have confidence in the Yukon Energy to plan and develop new clean energy. The confidence level indicated in the phone survey showed a slightly higher level of confidence at 56%. Using both data sources suggests about half of community business leaders have confidence in the corporation in this area.

> Note: Question 10 asked respondents to identify what they felt was the 'most important' thing the Yukon Energy Corporation needs to consider regarding Yukon's future energy needs. See Appendix B for verbatim comments.

11. How many years have you been a Yukon resident?



Consistent with the phone survey of community and business leaders, two-thirds (67%) indicated they have been a Yukon resident for over 20 years. This length of residency provides a strong historical perspective and experience in relation to Yukon energy issues.

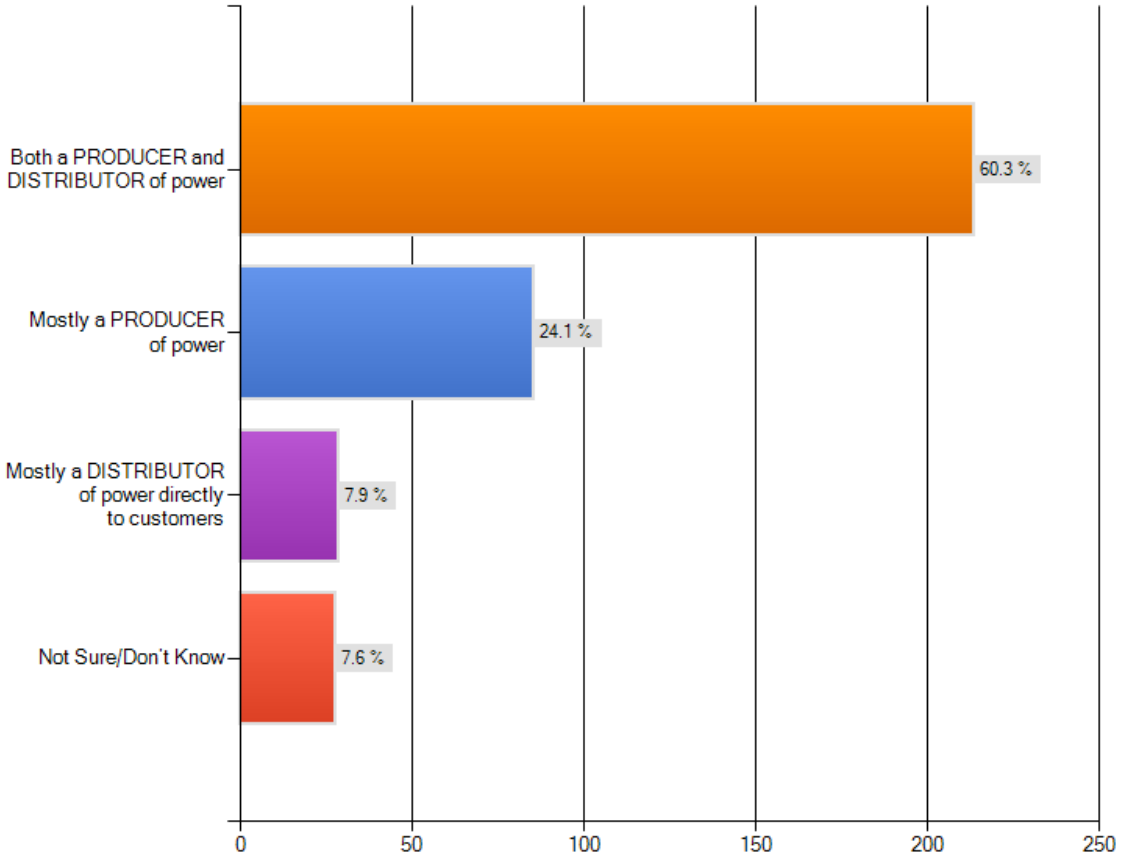
> Note: Twelve per cent (12%) of the community and business leaders who were sent an email invitation by the corporation to participate in the survey indicated they are not Yukon residents.

SECTION IV
Findings from the Public Online Survey

Introduction

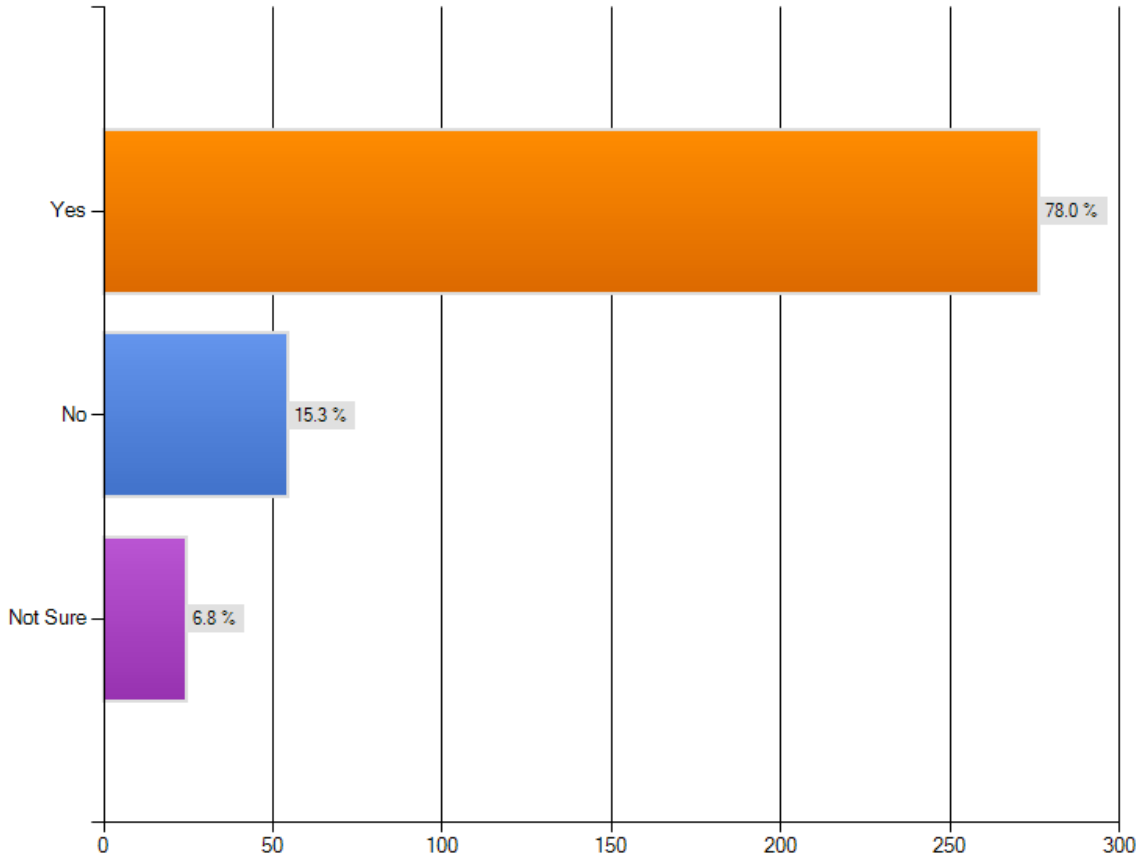
An open online survey of Yukon residents was conducted between June 15 – July 1, 2010. The survey was promoted through social and mainstream media and the Yukon Energy Corporation website. An incentive was offered to increase participation. The target of 180-200 respondents was surpassed at 356 participants. The survey achieved a 93% completion rate which means of the 356 who started the survey, 330 completed and submitted the survey.

1.1 Which of the following best describes the Yukon Energy Corporation.



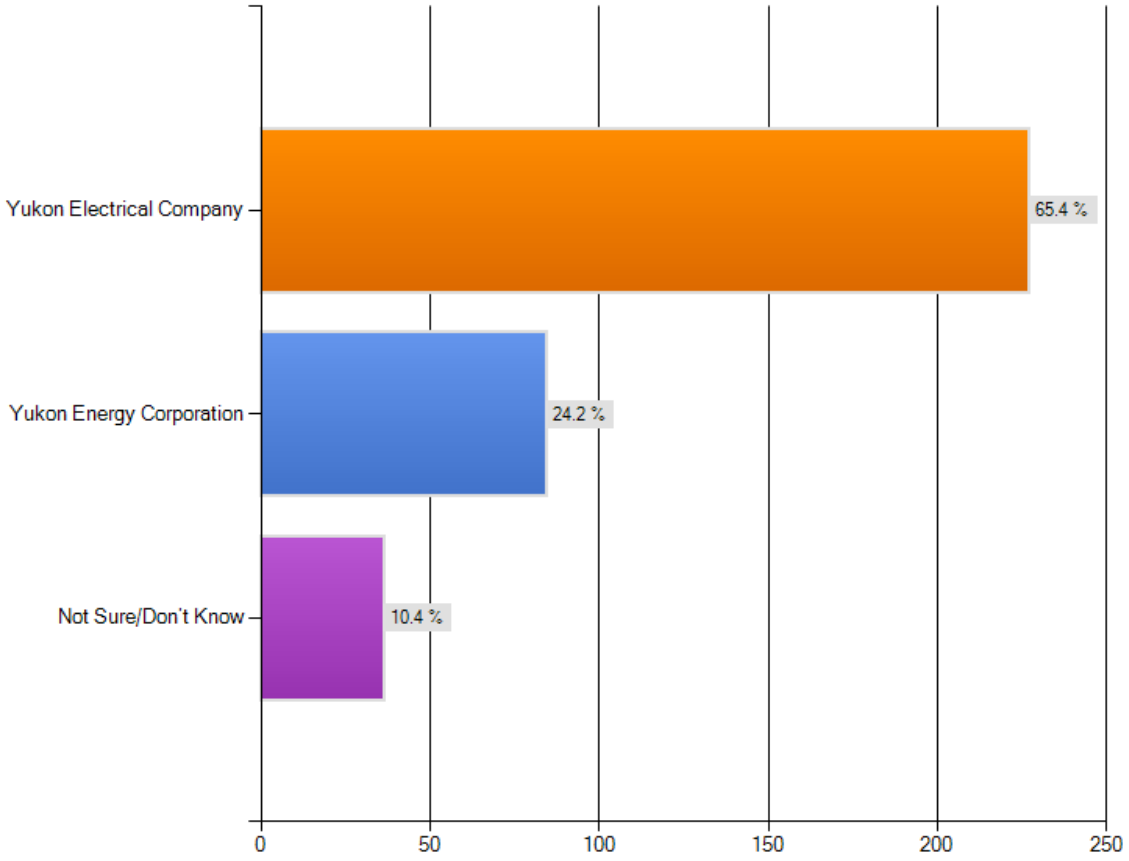
Just over fifteen per cent (15.5%) of Yukon residents indicated they either did not know (7.6%) the primary function of the Yukon Energy Corporation or thought the corporation primarily distributed power (7.9%). The majority (60%) of respondents are aware the corporation has a dual role of producing and distributing power and almost one-quarter (24%) said the corporation is mostly a producer of power.

1.2 Is it important to you to know who PRODUCES power and who DISTRIBUTES power in the Yukon?



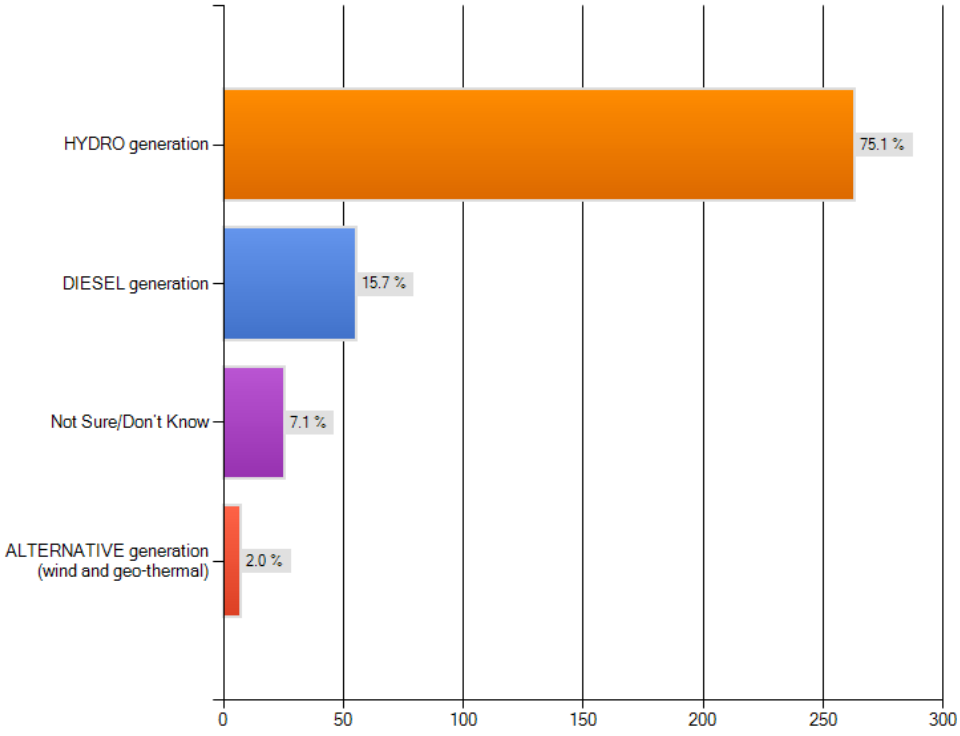
Seventy-eight per cent (78%) of Yukon residents said it is important to know who produces power versus who primarily distributes power. Clarity about the corporation's mandate may be a consideration for future public communications.

1.3 Who would you most likely call to report a power outage?

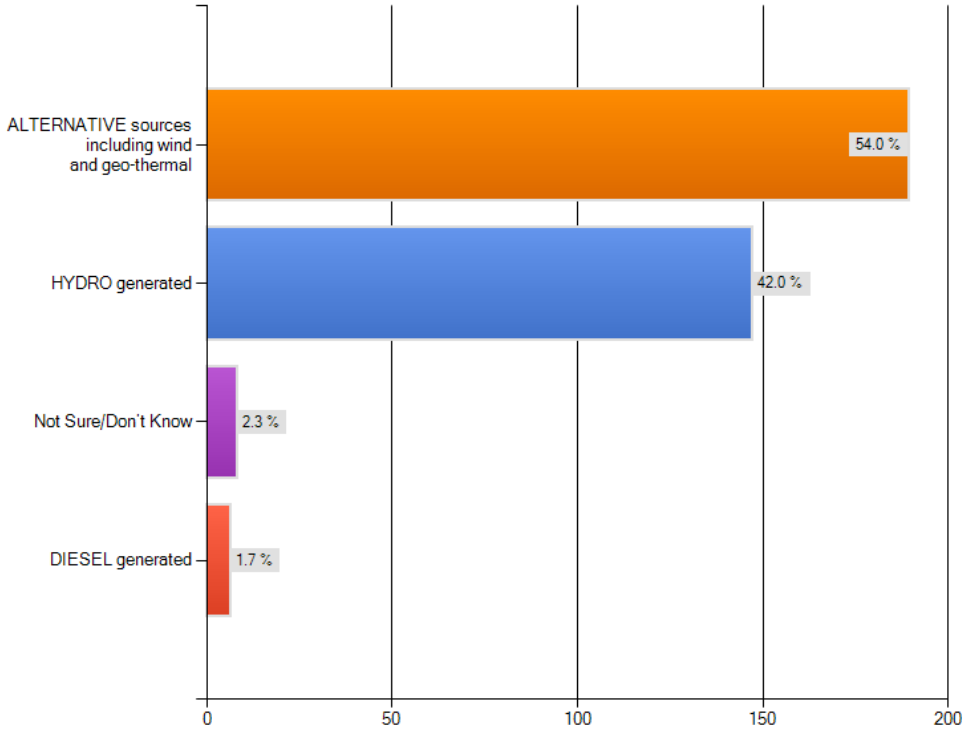


In assessing responses to the question of who to call to report a power outage, it is important to recognize that respondents included communities where the Yukon Energy Corporation is both the producer and supplier of power. It is also important to note the majority of survey respondents were Whitehorse residents and see the Yukon Electrical Company as their supplier and therefore the company they would call to report a power outage.

2.1 Which generates the MOST power in meeting Yukon's energy needs?



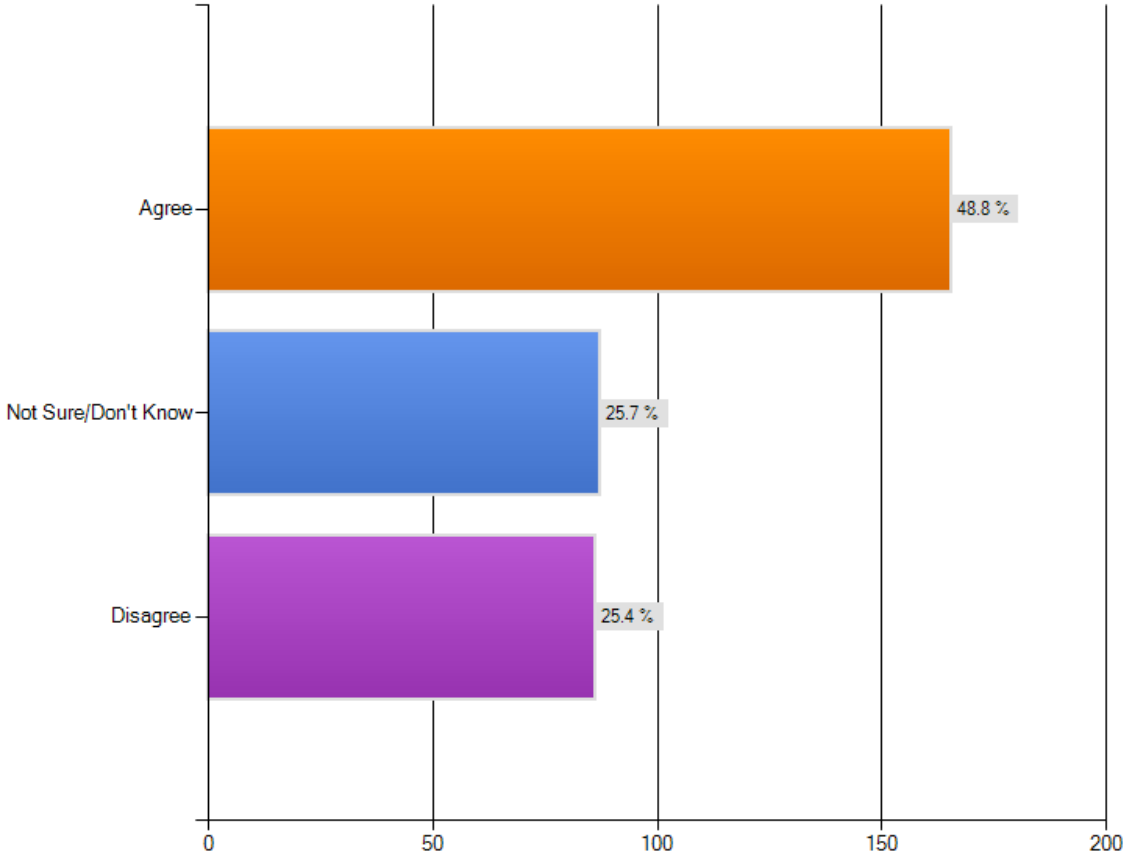
2.2 If you could choose how the power you use is generated, which would be your PREFERRED choice?



Three of every four (75%) Yukoners are aware the majority of their energy is generated by hydro, and over half (54%) would prefer to get their power from alternative sources if it were an option.

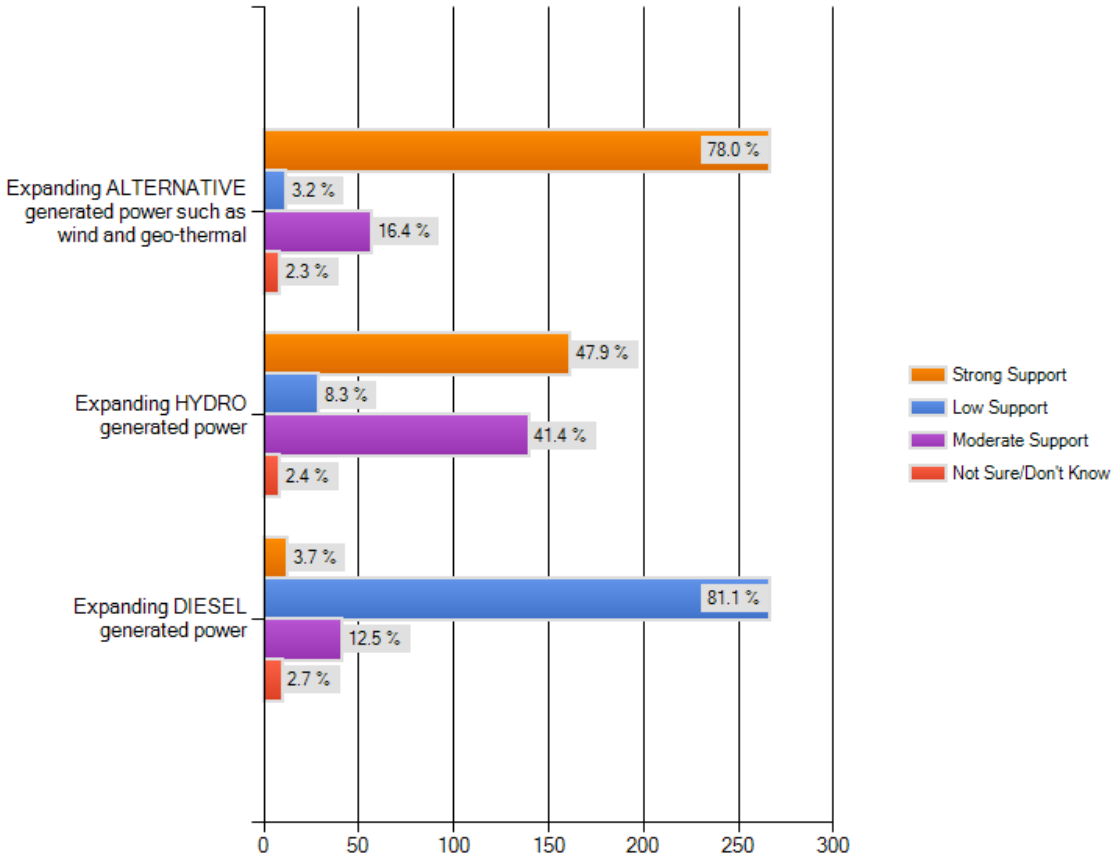
Note: No cost factors were included when survey respondents were asked to identify their "preferred choice". For the purposes of analysis, it is assumed that – all things being equal – respondents answered this question with an understanding that, when asked to compare, the cost of alternative source generated power would be the same as hydro generated power.

3.1 At the current rate of growth in power production, Yukon will not have enough power to meet future needs.



Almost half (49%) of Yukoners agree with the position that action needs to be taken to ensure Yukon's future energy needs are met if the current rate of growth continues. An equal number (25%) said they disagreed with this statement and a equal number were not sure of the accuracy of the statement.

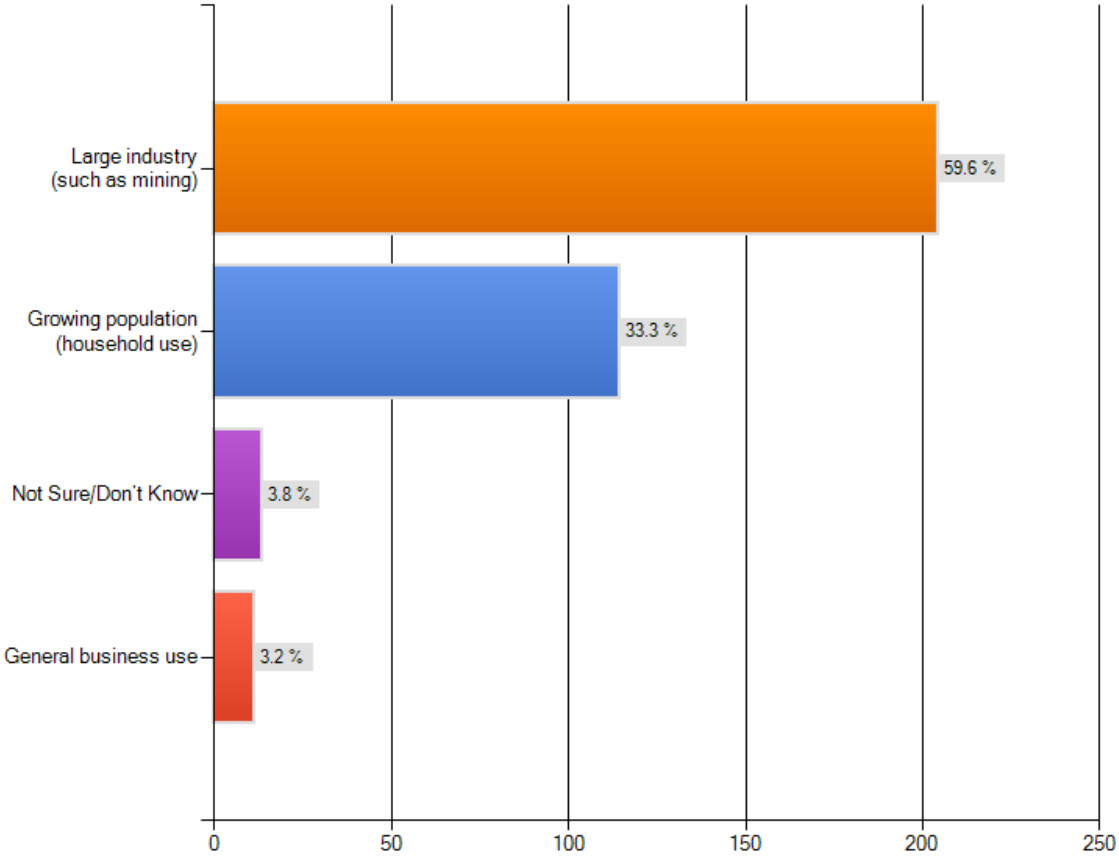
3.2 What level of support do you give each of the following power generation options?



A strong majority of Yukoners (78%) clearly favor expanding alternative generated power sources and are 81% are not in favour of expanding diesel-generated power. Slightly less than half (48%) indicated strong support for hydro generated power with an additional 41% giving moderate support to hydro power.

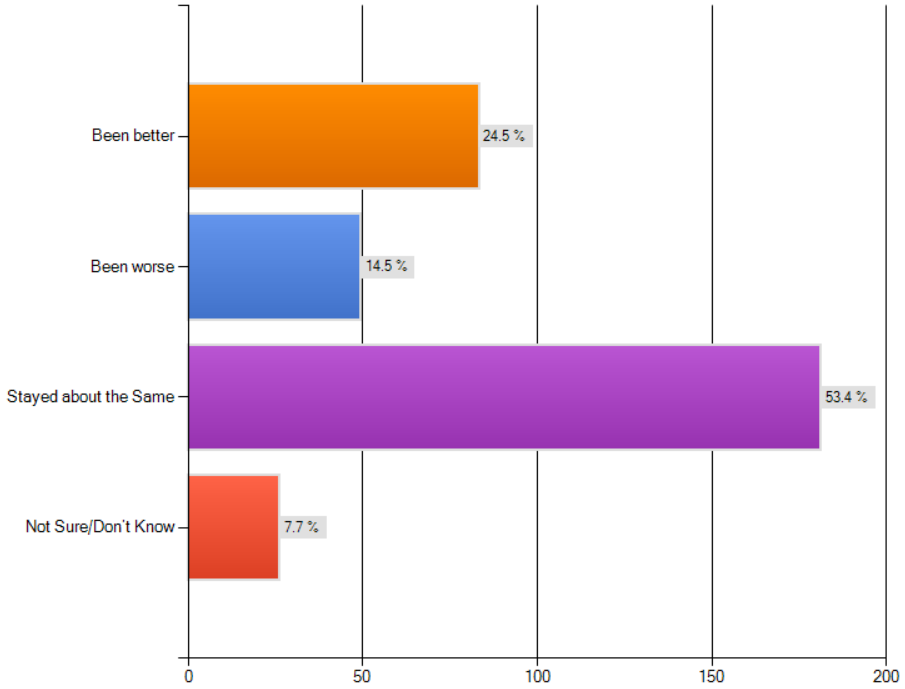
No development related costs were attached to the various power generation options, therefore alternative sources should be viewed as an “ideal” for most Yukoners. Factors related to cost, distribution, availability and reliability are all key to developing a fuller understanding of where Yukoners stand on alternative versus other energy sources.

3.3 Which of the following will create the SINGLE GREATEST DEMAND on Yukon's future energy needs.

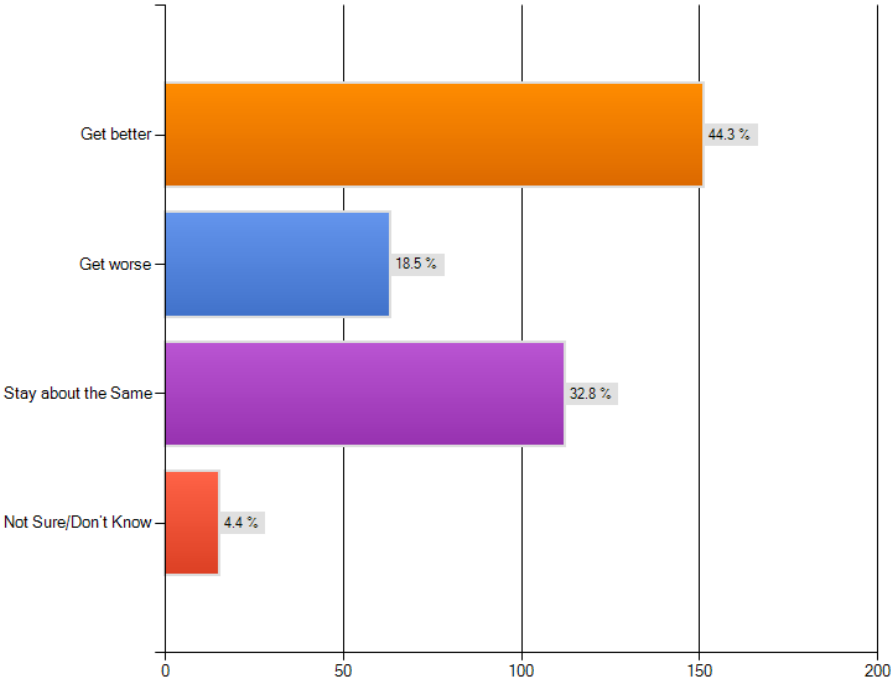


A majority of Yukoners (60%) see large industry as the big driver when it comes to meeting future energy needs while fully one-third (33%) see the growing population and related household use as being of greatest impact.

4.1 Over the past 12 months, reliability in the supply of power has:

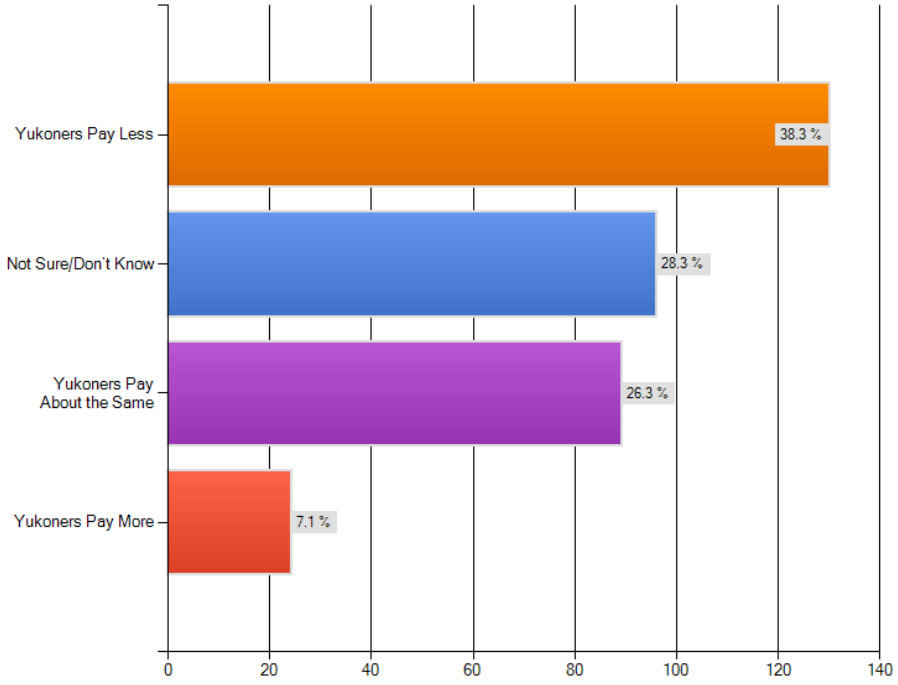


4.2 In the next 5 years, I expect the reliability of power to:

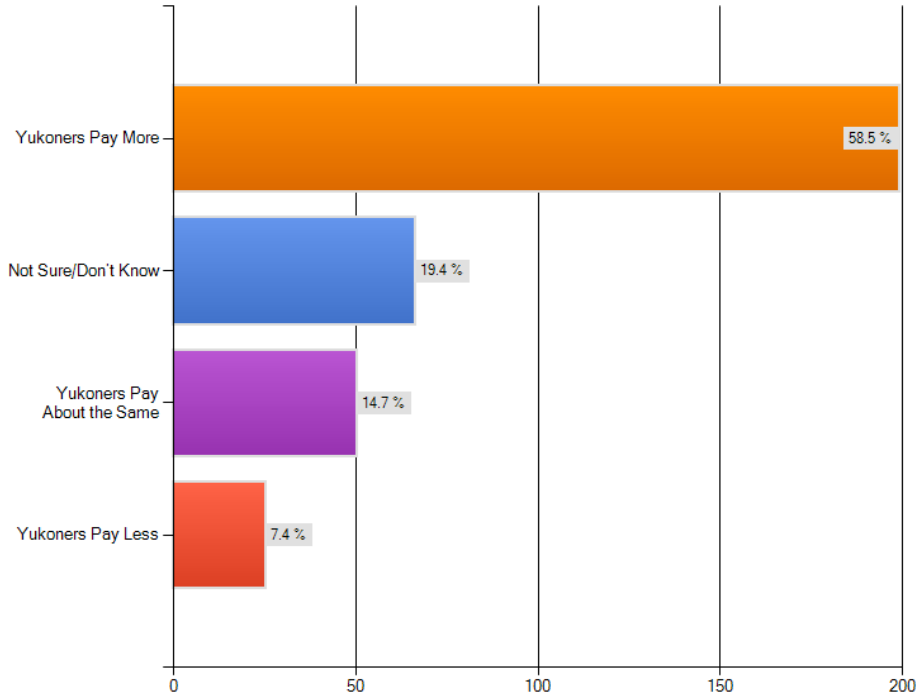


A slight majority (53%) of Yukoners feel the reliability of their power supply has remained about the same over the past 12 months, and 44% feel that the reliability is going to improve in the next five years. One-third (33%) expect no change in reliability. Just under 15% of Yukoners said reliability worsened over the past 12 months and just under 19% feel reliability will continue to get worse over the next five years.

4.3 Do you think Yukoners pay MORE, ABOUT THE SAME or LESS for power as compared to what residents in the NWT and Nunavut pay?

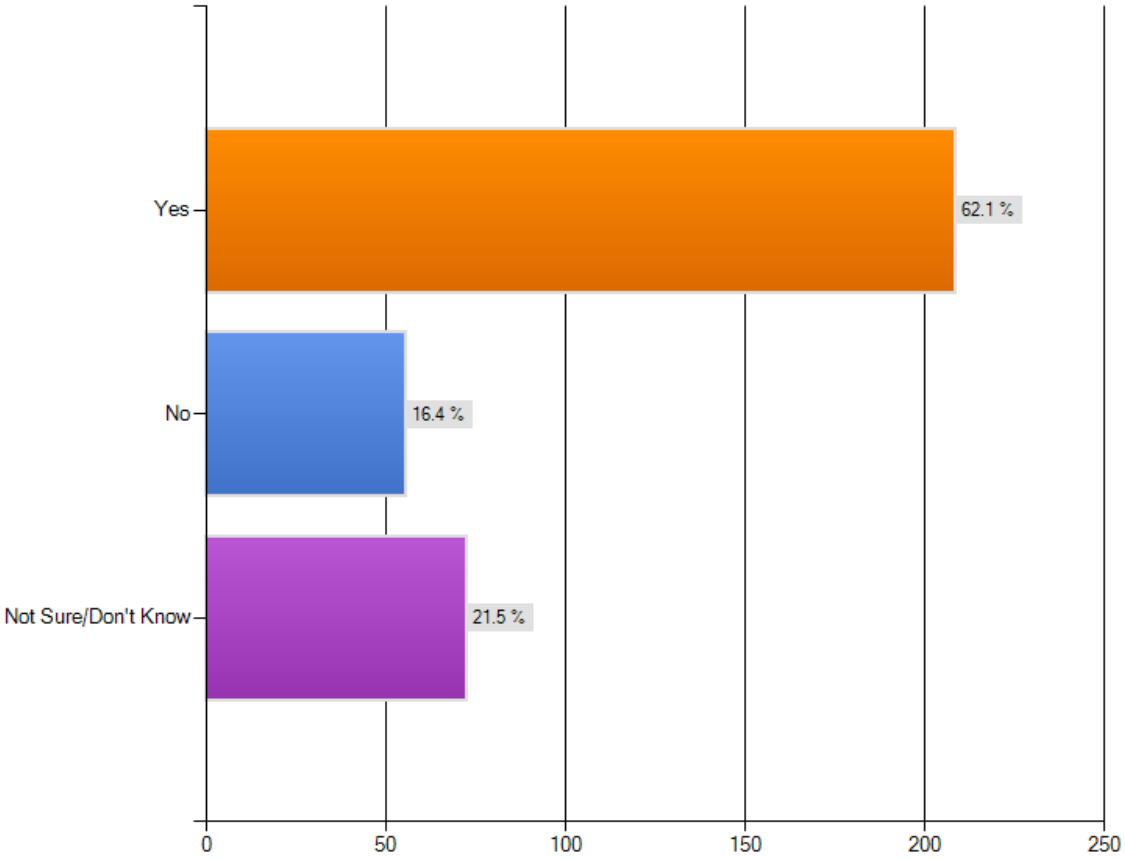


4.4 Do you think Yukoners pay MORE, ABOUT THE SAME or LESS for power as compared to what residents of Edmonton pay?



With regard to the perception of how much Yukoners pay for power relative to their northern neighbours in the NWT and Nunavut and residents of Edmonton, almost two-thirds (65%) said they pay the “same or more” than other northerners and an equal number (66%) said the pay the “same or less” than residents of Edmonton. This indicates a general sense that power costs more in the north than in southern regions.

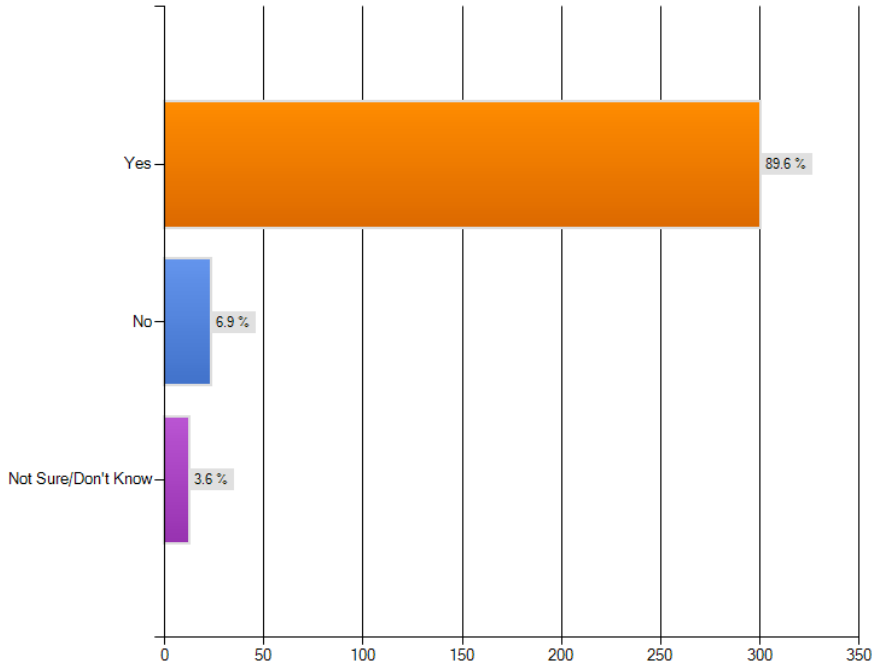
5.1 Do you have confidence in the Yukon Energy Corporation to plan and develop clean energy sources to meet future demands?



Over 60% of Yukoners said they have confidence in the Yukon Energy Corporation’s ability to effectively plan and develop clean energy sources to meet future needs. This is slightly higher than those who responded to the telephone survey where 58% said they have confidence in the corporation. Of important note is that between 18% (phone survey) and 22% (online survey) were unable to state their confidence or lack confidence in the corporation’s ability.

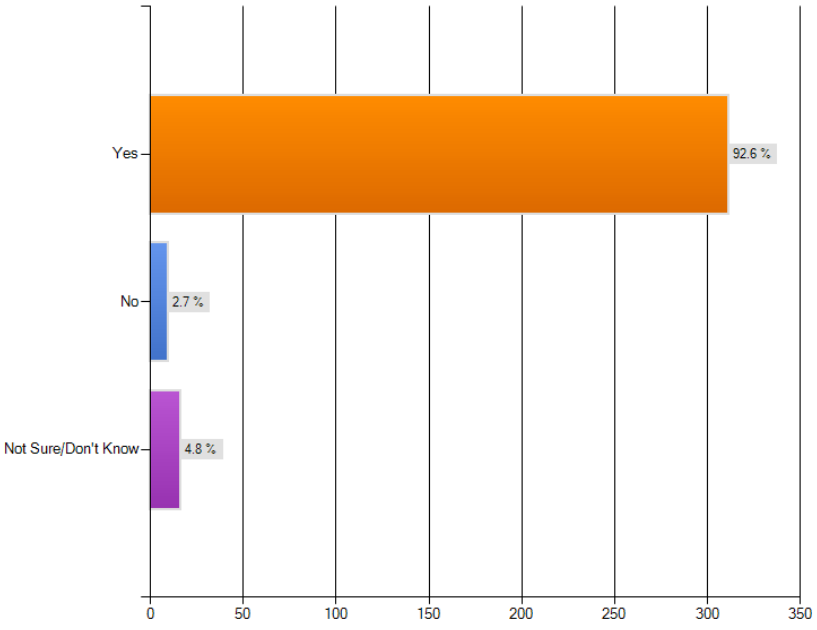
The results reflect an opportunity to improve overall confidence levels.

5.2 Do Yukoners need to do more on a personal level to conserve energy use?

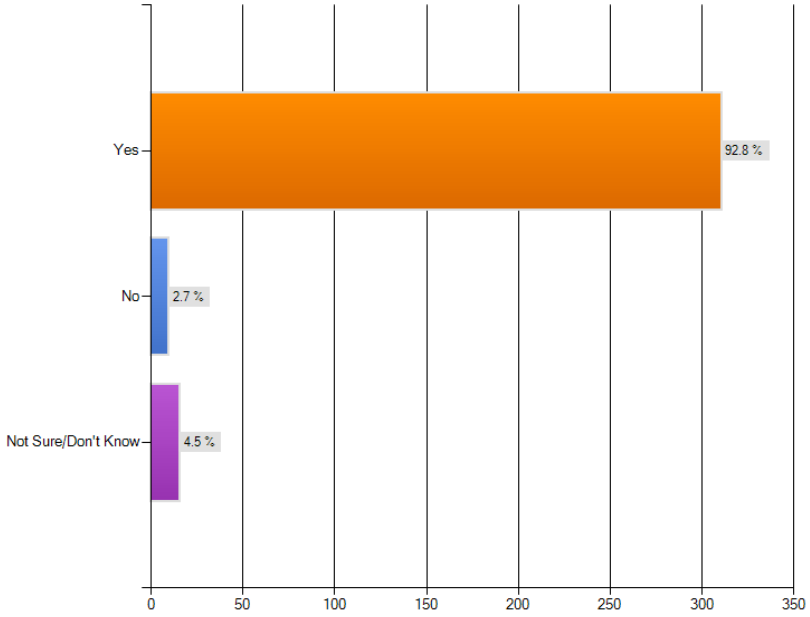


A high percentage (89%) of Yukoners agree they need to do more on a personal level to conserve energy. Response rates to this question were identical in both the online and phone surveys. This indicates a key opportunity for educating and assisting Yukoners in becoming better energy consumers. Ninety-three percent say business and industry needs to do more to conserve energy indicating energy conservation is seen as a shared responsibility.

5.3 Do business and industrial users need to do more to conserve energy use?

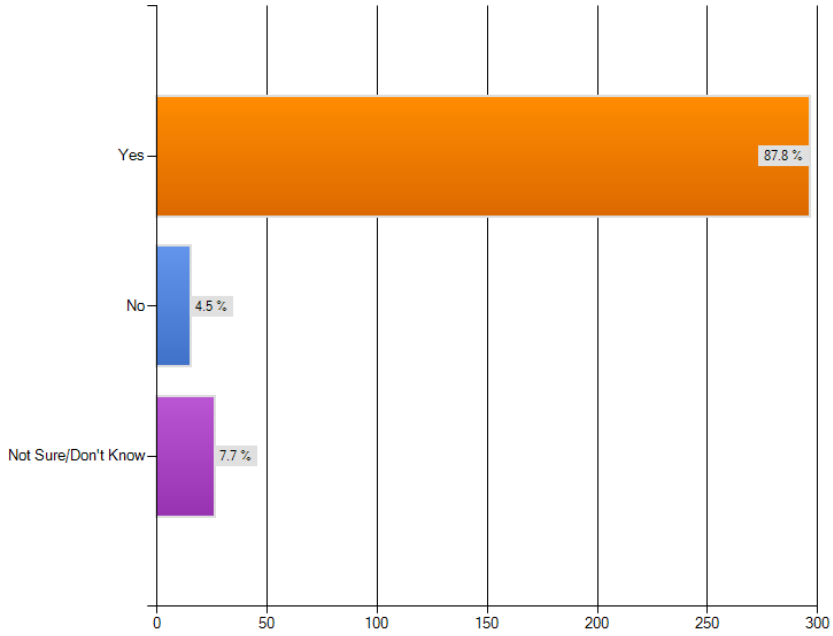


5.4 Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?



Almost 93% support for developing alternative energy sources is consistent with a previous question that showed 78% strong support and 16% moderate support (94% combined strong/medium support) for the development of alternative energy sources in addition to new hydro sources. This indicates a very strong desire for the Yukon Energy Corporation to pursue development of alternative energy sources as the corporation moves forward with larger scale hydro development to meet future needs.

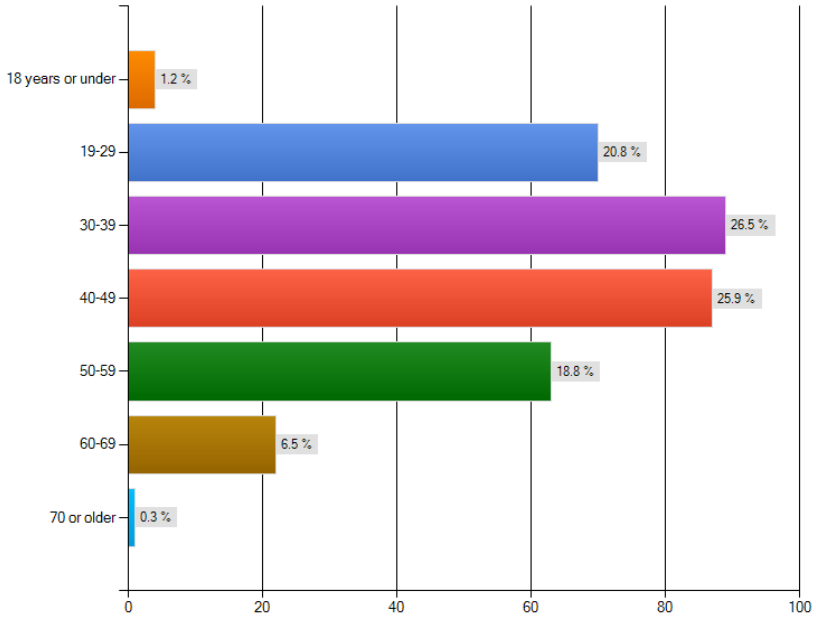
5.5 Is moving away from a reliance on diesel-generated power the right thing to do?



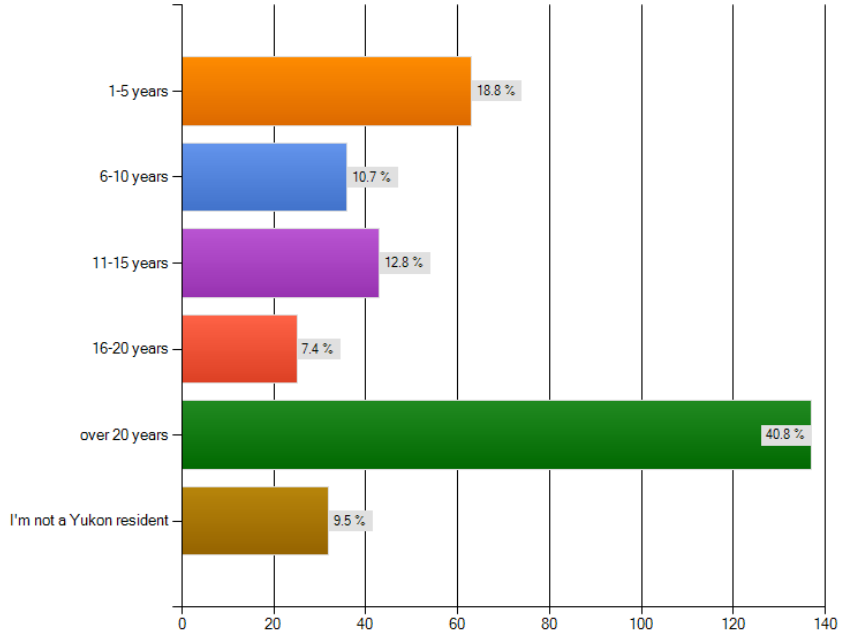
Consistent with support for the development of alternative energy, Yukoners also see diesel-generated power as the least desirable energy source with 88% agreeing that moving away from this source of power is desirable. Comments from the survey however, also indicate an understanding among some respondents that diesel is necessary in some communities and that it provides an important back-up system.

Online Survey: Demographic Data

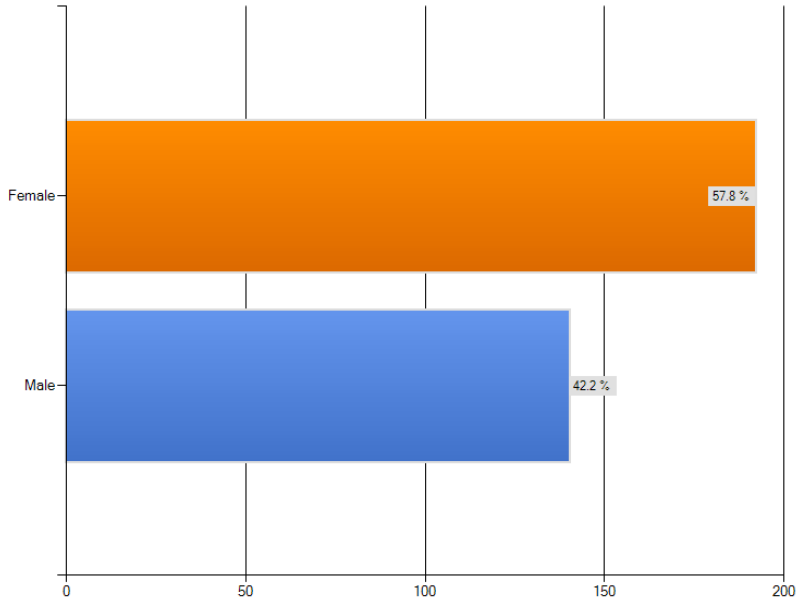
Respondents by age grouping.



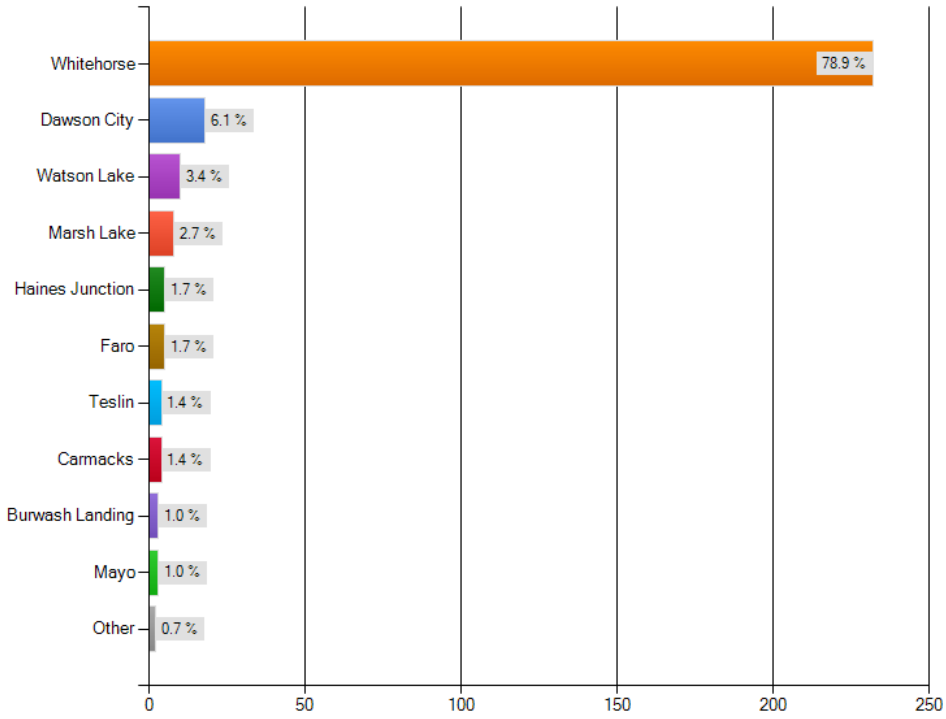
Length-of-residency in Yukon.



Respondents by gender.



Respondents by community.



APPENDIX A
Knowledge, Awareness and Opinion Research Overview

Public Telephone Survey:

Conducted:	June 2 – 8, 2010
Sample Size:	184
Selection:	Random
Surveyed Communities:	(6) Whitehorse , Marsh Lk., Teslin, Carmacks, Haines Jct., Dawson City

Public Online Survey:

Conducted:	June 15 – July 1, 2010
Sample Size:	356
Completion Rate:	93%
Selection:	Open, web-based, promoted via media/social media
Communities:	17 (Yukon) 20 (non-Yukon) (326 = Yukon residents: 30 = Non-residents)

Community and Business Leaders Telephone Survey:

Conducted:	June 4 – 11, 2010
Sample Size:	25
Selection:	Client/Agency Consultation
Communities:	(5) Whitehorse; Mayo; Faro; Watson Lk.; Champagne-Aishihik

Community and Business Leaders Online Survey:

Conducted:	July 7 – 15, 2010
Sample Size:	41
Selection:	Email invitation
Response Rate:	82%
Completion Rate:	100%

Total all Methodologies:	**606**
Confidence Level:	**95%**
Confidence Interval:	**4**

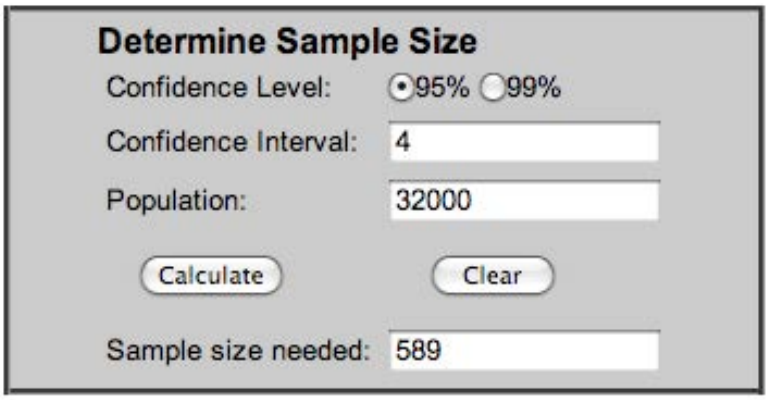
See following page for description of sample size calculation for confidence interval and confidence level.

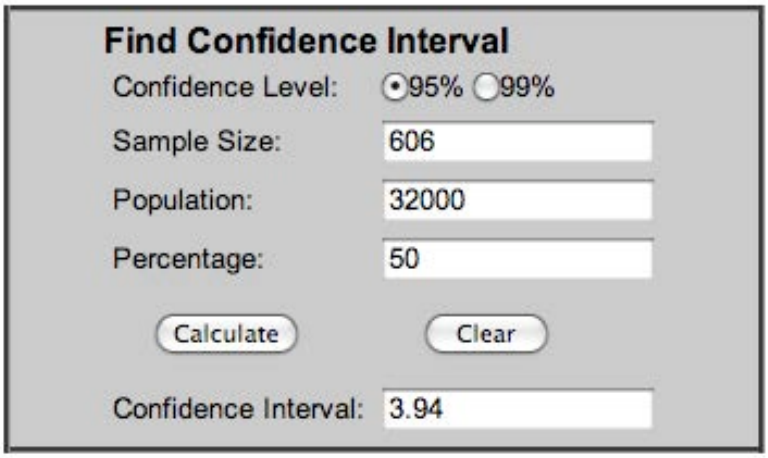
Sample Size Calculation:
Confidence Interval and Confidence Level

The **confidence interval** (also called margin of error) is the plus-or-minus figure usually reported in newspaper or television opinion poll results. For example, if you use a confidence interval of 4 and 47% percent of your sample picks an answer you can be "sure" that if you had asked the question of the entire relevant population between 43% (47-4) and 51% (47+4) would have picked that answer.

The **confidence level** tells you how sure you can be. It is expressed as a percentage and represents how often the true percentage of the population who would pick an answer lies within the confidence interval. The 95% confidence level means you can be 95% certain; the 99% confidence level means you can be 99% certain. Most public opinion research uses the 95% confidence level.

When you put the confidence level and the confidence interval together, you can say that you are 95% sure that the true percentage of the population would have answered the question in the same way as indicated in the obtained survey responses within an 8% range. The wider the confidence interval you are willing to accept, the more certain you can be that the whole population answers would be within that range.





APPENDIX B

Verbatim Comments: Business and Community Leaders Online Survey

Following are verbatim comments from the community leaders online survey. The survey was conducted in July 2010. Approximately 50 community and business leaders were invited by email to take the survey with 41 (82%) participating. Completion rate was 100% meaning that everyone who started the survey completed the entire survey.

Comments should be viewed in conjunction with the statistical data for these questions.

Author's Note: While the survey comments below are presented verbatim, some have been edited to ensure confidentiality including the removal of any names, personal references or identifiers.

Q 6. Should business and industrial energy users be developing plans to use better energy conservation technologies, equipment and operational practices to help reduce demand?

1	The best energy conservation policy is charging what it really costs to generate power as well as expand generation capacity.
2	Need a rate structure to give off-peak hour use
3	The high price of power in the Yukon ensures that users are already focusing on this; I do not believe that further studies would be cost effective.
4	i think govt and its depts need to lead the way on this.
5	New power sources are expensive and some energy conservation should be employed.
6	Power should be more affordable
7	government should not always feel the need to subsidize energy for mines. if the mine can't afford to create its own energy or pay a fair price its not viable
8	Higher efficiencies are good as they save businesses money and reduce demand, however there needs to be support for using electricity as an energy source as it's clean and easy to use. Don't penalize companies for wanting to use electricity.
9	All businesses and industries should be trying to conserve and reduce energy use.
10	this is a stupid question. Any business will try to achieve economies wherever they can.
11	no
12	Obviously better development planning and lowering costs should improve the bottom line.
13	Turn computer off, turn lights off, power electronic devises down.
14	Business and industrial users will respond to costs...if demand costs dictate conservation, then conservation will happen. Otherwise, it will not. So, structure the rates accordingly.
15	Only as long as costs do not get out of hand.
16	Of course, only a fool would say no to this.
17	But it has to be at a reasonable cost...we all have our own contributions to make to the overall energy challenge in Canada as a whole.
18	Time-of-day metering (cheaper rates at low demand times/seasons). Permit homeowners and business to generate power (solar panels, wind, etc.)

Q 7. Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?

1	Consider Natural Gas
2	Alternative energy sources will never provide base load generation but they should be developed as a companion to expansion of base load capacity
3	Geothermal – Yes. Wind -No
4	Where they are cost competitive. Alternative energy sources must be cost competitive - considering both capital and operating costs and effective utilization
5	2 things; i believe we need to be interconnected to the north American grid - expand the lines south, not north. and are we not able to look at natural gas generators instead of diesel?
6	Some forms of alternative energy will provide a cost-effective method of meeting new generation requirements and improve electrical grid stability and reliability as well as keep more of our ratepayer's money in the Yukon
7	maybe geothermal but so far the wind energy at heckle hill is a failure
8	Geothermal may be an option. Yukon Energy hasn't explained to the public enough of what's happening in regards to geothermal. Wind energy I do not support in combination with hydro.
9	Wind power in the Yukon has been a joke. Not sure about geo-thermal Hydro if it makes sense. LNG makes a lot of sense. Natural gas turbine plant makes sense
10	Absolutely not, unless these are the most economically viable energy sources. So called alternate energy sources should not be subsidized by the rate-payer nor the taxpayer. It is a waste of limited economic resources. It is a boon only for utilities (receiving taxpayer and ratepayer subsidy).
11	Hydrogen. The key is not generation but storage, effort should be directed at storage research/solutions
12	no
13	If either wind or geothermal sources can be cost effectively developed and operated and not just token efforts to keep the greenies happy, then certainly. YEC should be run as a business and its' decisions should make economic sense.
14	We don't use enough, more wind for sure
15	Not until it is cost effective. At present, I don't believe that it is so.
16	Costs are the limiting factor with these alternatives. What about natural gas?
17	If it is feasible and affordable, of course.
18	They tend to be very high cost and not generate a lot of power so looking at them for a solution to the energy challenge for large industrial operations is probably quite impractical
19	where economically feasible

Q 8. Is moving away from a reliance on diesel-generated power the right thing to do?

1	Yes. However they do provide much needed back up
2	Petroleum fuels are a limited resource and continue to escalate in cost whereas renewable projects have fixed costs and do not rely on depleting resources
3	lets be realistic. sure its the right thing to do but only if and when its cost effective
4	But not entirely, particularly in the remote areas. Some diesel-generated capacity is also necessary for standby emergency purposes.
5	Need diesel as a back up and maybe remote communities
6	Where diesel is the more expensive energy sources we should be looking for other alternatives - like Hydro, clean coal, mini nukes, natural gas from the Dempster. What is most economical?
7	Unless you can economically use the waste heat.
8	Of course, but it should remain as a reliable back-up source.
9	It should incorporate other options such as clean coal and natural gas
10	Where economically feasible

Q 10. What is the ONE MOST IMPORTANT thing that Yukon Energy needs to consider regarding Yukon's future energy needs?

1	Keep energy cost effective
2	Consider clean coal or coal gas generation from the Division Mtn coal field at Braeburn
3	The focus should be on projects which are large enough to ensure a consistent supply with a margin of overcapacity to supply future industrial activities.
4	Need to think about individual customers and not just big industry. i tried calling to speak to someone about outages - no response and no one really cared. i would imagine if i was minto mine, someone would talk to me.
5	Yukon Energy needs to first solicit all of its new power from independent power producers on a take or pay basis as is done in most of the rest of North America. Yukon Energy should stay on to manage the transmission and existing production but should look to the private sector for new energy sources. The Mayo B project is an example of the high cost of new utility-based projects. This load requirement should have been put out to the private sector first
6	Developing alternate source of energy such as Hydro, Wind power etc.
7	Bring in Power to support mining development. There are major deposits in Yukon that could be developed if power was available. This would create a lot of jobs and wealth for Yukon. These developments are not likely to proceed unless the power situation improves.
8	Cheap long term power
9	Greenhouse gas
10	Complete a grid of all yukon/northern bc
11	I don't think government or government corporations are agile and creative enough private sector will provide energy solutions in the future as energy becomes more expensive.
12	I have confidence that they can deliver the energy. I do not believe Yukon Energy has done a good job or is continuing to do a good job in making the clean energy projects cost effective. Private industry can build it cheaper by far.
13	Location of new / additional power generation infrastructure relative to new industrial developments (e.g. mines).
14	Look at developing a Natural gas Turbine plant. Tie the grid into B.C.
15	Develop our energy needs in the most prudent, economically efficient manner possible. Your job is to develop energy at the lowest possible cost to the rate payer with no subsidy from other levels of government. All other agenda's are someone else's responsiblity. The Mayo B is a travesty. 160 million for 6 megawatts of power is not providing electricity at a very economic price. 26million per megawatt - what a joke.
16	a multi faceted approach which will bring a diversity of options and solutions; the traditional utility model does not do well with uncertain circumstances and the ability to deliver innovative and creative solutions. So, in addition to the traditional consultants, non- traditional creative thinkers/entrepreneurs should be encouraged. Vision will be required
17	Future demand
18	Sustainability
19	Availability of petroleum will become constrained, and cost will increase greatly. Guaranteed.
20	SE Yukon's dependence on diesel
21	Reliability and accountability. That means don't blame every brown out or spike or outage on squirrels and ravens. If the line is 10 metres off the ground and the trees 15 meters tall, the right of way should be cut and maintained so no tree can hit the line.
22	Become self-substainable. Get off of diesel, ridiculous and disgusting, and embarrassing.
23	Reliability, followed closely by affordability
24	Large mines should develop and pay for their own power generation. Yukon Energy Corp should not be involved in short term, large scale projects. It is not their job. If we have excess generation, by all means sell it, but don't develop large-scale projects for short term projects at our risk and expense. Stick to the mandate of providing reliable, affordable power to the Yukon people. This is a simple task if not confounded by mining mega projects that are risky at best. If they are not feasible without grid power, let them wait until they are.
25	Be prepared for future needs by industry.
26	How to derive large energy sources...+50MW...for operations like Casino, Northern Dancer,

	Selwyn...and the Klondike/Rau/Eagle will likely generate new projects requiring clusters of energy
27	Reasonable cost with reliable service.
28	Reliability -- I'm tired of re-setting my clocks every couple of days
29	Let Yukoners invest in the Yukon to promote YEC ie: Like Air North did to get off the ground
30	Clean energy and protection of fresh water.
31	Forays into alternative energy seem hesitant (e.g. wind), and the proposals for private energy producers (micro-hydro, solar, etc.) are restrictive compared to other jurisdictions.
32	cost to customers
33	Stable rates.

APPENDIX C

Verbatim Comments: Public Online Survey

Following are verbatim comments from the public online survey that was conducted between June 15 and July 1, 2010 and achieved 356 responses with a 93% completion rated, meaning that 93% of those who started the survey completed it. In total, residents from 17 Yukon communities participated. In addition, 30 non-residents of the Yukon also participated in the survey.

Of particular note is that 27% of survey respondents took the time to write a comment. Coupled with the high response and completion rates, the number of comments recorded indicates a high degree of interest in the topic of Yukon's energy future.

Author's Note: While the survey comments below are presented verbatim, some have been edited to ensure confidentiality including the removal of any names, personal references or identifiers.

Q . Do you have a comment about Yukon's energy future?

1	One word: Geothermal.
2	I am curious what is happening with the windmills. They don't always seem to be operating. I hope the YEC Board is supportive of alternative energy, including energy conservation.
3	Where any hydro expansion is necessary to meet power demands, it should be accompanied by education campaigns targeted to both private and industrial users on the importance of limiting consumption. While in an ideal world we could expand only with alternative energy sources, we don't seem to be there yet, and Yukoners don't seem to be prepared to foot the bill. Any new hydro undertaking or expansion must be carefully studied, preferably by an independant third party, to ensure that habitat is not being negatively impacted by YE activities or infrastructure. Monitoring of impacted terrestrial and aquatic environments should take place over the duration of the project at a much greater degree than what may be provided for by the water license.
4	Start by promoting conservation.
5	Less of a foot print is the goal. renewable energy is a blessing and we are aware of the technology. We must use it. Geo-thermal has barely been tapped, and it can do so much.
6	Behind door politics, such as (reference removed) trying to sell off part of our assets, should be avoided at all costs.
7	I do not want an unregulated, private owned energy corporation.
8	I hope they have a plan for the future if industry leaves.
9	Sounds like Yukon Energy already knows what to do, just needs Yukoners and the YG buy in! Can't wait to see what happens!!
10	Should promote homestead small scale energy generation and be able to sell excess back to grid.
11	Develop alternative energy
12	Make it more reliable - less unplanned power outages
13	Not at the expense of the environment!
14	Focus on micro-hydro, wind, geothermal and allowing people to generate their own power and sell it to the grid.
15	I am extremely opposed to the idea of clients using less power getting a discount. I installed electric baseboards in my new house as back-up for my woodstove, because I felt it was the greenest option. It does not fit with Yukon Energy's mission & philosophy to reward & encourage people to burn oil for heat. I can see how it would be less of a problem for Yukon Energy, but if you want to build better, healthier communities, this is not the way to do it. I would like to see a lower evening rate. I have no idea of how much that would cost, but it

	may be able to balance the draw better. It would be incentive for people & businesses to make changes and be more aware of their power usage.
17	Natural gas (alternative)
18	What about natural gas?
19	promoting the use of hydro and wind electric is better for the environment and possible for the North. Yet YEC continues to penalize people for choosing this form of green power to heat their homes. YEC has the ability to one day provide hydro power with out the use of diesel to all of us. This should be encouraged, rather than discouraged.
20	I will add my comment here since there seems to be no other place.....I am very dissatisfied with the power we get in whitehorse. Numerous times I have measured the power at my house and it is NEVER 120, always 110 or less. Constant brownouts, power outages make me think I am in a 3rd world country at times. The power supply in the Yukon is substandard in my experience. Hard on equipment, motors, computers etc. It has gotten better in the last year but has a long way to go.
22	hopefully they use the wind as it is always blowing up here but i am no expert on that type of use
23	Question 4 should have an option offering developing alternative energy sources without tying it to new hydro sources. By selecting Yes to agree with developing wind energy etc., by default I must endorse development of new hydro sources. I do NOT endorse new hydro energy sources carte blanche and feel this is a dishonest question.
25	Over dependence on fossil fuels is a major cause of global instability.
26	Because of our geographic location and the associated challenges, diesel power backup of our grid is essential to the safety of all Yukoners,
28	They will do well if we can get rid of the territories dependency on fuel to light their homes etc.
30	Hydro should be expanded where possible and supplemented by large amounts of wind. I feel that wind is the most economical, reliable and realistic clean energy source for YEC to pursue. It may not be available at all times but when it is the reservoirs for hydro can be filling (storing) power for later use. Furthermore, combined heat and power using biomass (our forests) as fuel would make a lot of sense here since when the heat demand is the greatest, the electrical demand also peaks! This would require YEC to sell heat as well as electricity, but it is a large utility that could figure that out as well. Downtown Whitehorse has potential for a district energy system that could be the first consumer of this heat.
33	Yukon is a beautiful, fairly pollution-free place. Reliance on diesel-generated power is unfortunate, as it creates more air pollution. It's fantastic to see new projects like Mayo B being brought in, to help with hydro power generation.
32	sustainable energy is key
33	Quite frankly I have been angry at the exorbatent rates we have been getting - but through our observance of ways to lower our power bills we can tell that if others followed suit they could lower theirs as well - while we need power we also should be more careful how we use it - small/home businesses should also have their rates lower - our small local businesses get bit in the butt every month by a huge amount for power - that a lone closes many of them down - our small local businesses should be thriving rather then closing due to every cent they make going to the power and phone bills. etc. If you can't make any money then how can your business survive ..... we all need to eat and pay the bills!!!! The power is the worst of it!
34	Do everything they can to get away from Diesel .... the cost will be too high
36	Be realistic and yet think of the people who live there. To help people with their health and the environment.
37	it's time to accept the reality of our situation. time to change our ways. time for clean, efficient, affordable energy systems that put back 'in' not just take out. NO COAL, NO NUCLEAR, no more hydro, no more diesel.
38	Good to have as a backup power source
40	Emergency back-up power by diesel should be maintained, but some communities run diesel all the time. These should be priorities.
41	Let's get off fossil fuels. It is hypocritical to refuse to develop oil and gas in our own backyard while we use much much more than other parts of the world who suffer from the development that our use requires.
43	The future of energy in the Yukon or Yukon Energy's future? Very confusing questions.

	Congrats to whomever worded it-you're good! Yes we want enough environmentally responsible and affordable energy to meet our needs, but it should be developed in a fiscally responsible way as well.
44	I'd like to see more alternative choices, but realise that's easier said than done - expense, challenges to connect to the grid, technology issues etc.
45	Please allow home owners to produce electricity, and to be able to sell it back to the grid.
46	Bio fuel/Co-generation
47	Hopefully you'll stay Yukon owned and push for more alternative energy.
48	use your resources wisely and keep the Yukon a viable living space
49	Quit with the elaborate plans, and rate hikes! Affordable Power with out spending capitol because you can to get your 10% on investment!
50	Work with Yukoners to promote energy efficient programs and environmentally friendly alternative energy. This also will protect and promote our beautiful territory.
51	Go nuclear!
52	develop a better maintenance program in repair/replace outdated lines and equipment
53	all I'm saying.. if its not broken? why fix it?
54	Get rid of diesel!
55	I think there is a lot more to be done with alternative energy sources. The windmills could be hooked up to something viable, e.g. greenhouses, so people can actually see the opportunities alternative sources can provide. The use of geo-thermal in heating homes is another area that should be looked into more, and used.
56	I would like to see the legislation move forward allowing private power producers to sell their wind/hydro generated power to the grid.
57	they should have both as one can be a backup
58	DO NOT OUTSOURCE!!
59	More exploration into geothermal would be nice to see, even establish a pilot project like the Heckel Hill windmills
60	IPP must become a reality in Yukon.
61	The goal should not be a combined effort, but a process of switching completely to greener sources.
62	Yukon has already created scales of economy based upon hydro electricity... the ecological footprint is less in continuing to develop hydro electricity then it is in developing alternative energy sources. Alternative energy sources are not all that they are perceived to be. We may need to be reliant on diesel generation for back up systems and that is understandable...
63	Yes. Set the conditions for success. Meaning do what is right and move into the alternative energy sources. to continue to use diesel is just wrong and creating impoundments is not the answer either. I accept a balance but more wind and geo thermal would be better. It may cost a lot up front but the payoff down the road is worth it.
64	I've heard there's a radar-detection method of stopping windpower ...er, fans...to prevent bird deaths.
66	I think it's important to keep Yukoners informed as to what the future plans are and what we need to do to help (as the general public)....Provide schools and teachers with more hands-on materials to educate our young people.... Help us to help ourselves!!!! :)
67	bio-diesel
68	You have collapsed two very different sources (wind and geo-thermal) into one. I'm not in favour of any more wind-related investments. Geo-thermal is worthy of investigation. The key thing is to build more supply. The price per kW I paid for electricity in the lower mainland is a fraction of the cost I pay here. We need affordable, reliable energy as a key ingredient in our economic future. Yes, NWT & NU pay more, but look at the precarious state of their economies; more private development, especially in mining and industry, will only happen with reliable, affordable energy.
69	So far Yukon Energy has been reliable and cost-effective provider of electrical energy and consumers would like to see the same high level of customer service from this company. The company definitely needs to add alternate sources of energy like wind and geo as Yukoners believe in environment friendly solutions are the best key to some key challenges of future.
70	Even investigating bio-diesel would be a step in the right direction.

71	Diesel is the most reliable power.
72	At least in the short term, demand shaping (cheaper off peak power) should be considered. And WHY is it not common knowledge when the generating capacity is at the edge? People could schedule discretionary power use to help everyone if that information was available.
73	until some other source of power can be developed
74	We need to use the environment in a healthy way to provide us with the energy generation we require now and in the future. Along with that all Yukoners need to learn to conserve energy in their homes and businesses. Yukon Energy needs to ensure it can provide enough power for us to grow in industry and private homes. This may mean research into alternative energy sources.
75	(Don't) sell Yukon's interests down the road. I dont trust them (gov't)
76	More consistency & less power bumps would be easier to live with, or some protection device at the meter?
77	We need to get the 'politics out of the picture, we need the diesels as back-up power in case of outages
78	Yukon Energy needs to diversify their energy sources by developing wind farms, near Whitehorse.
79	YE is awesome! Have spoken to people in the company - very nice and helpful
80	Have a positive belief in an energy conscience population to do the right thing.
81	just want to make sure we keep warm in the winter !
82	More windmills, More geothermal, - more renewable, reusable, and clean energy. It will better many things.
83	It is more important to control demand than supply. It is almost as important that we have a widely distributed system of micro producers- all customers should be producers and Yukon Energy could be relegated to a producer of last resort and a coordinator of power production. Only thus will our energy security be assured
85	i hope to see more encouragement on people having their own power generation at home and it being able to feed back into the grid.
86	question 4 is double barreled. i want yukon to DEVELOP alternative energy sources on its own for its own accord, NOT in combination with new hydro. i have lots more to say about yukon's energy future. call me (name and phone number removed for confidentiality)
87	Yes, why is question 4 a loaded question? What if I support wind/geo-thermal, yet don't want to see new hydro developed?
88	Energy includes more than just power. We need to also be thinking about heat and transportation as well. Changes to these sectors may put more demand back on to the power sector if it is clean power.
89	For obvious economic reasons today and into our future, we must put our energy plans in place now. This kind of plan attracts investment in our communities and in our people. The longer delayed, the longer we remain a "have not" part of Canada.

Prepared for the Yukon Energy Corporation
by Andrew Hume and Associates Ltd.
in association with Aasman Brand Communications

July 21, 2010

SUMMARY REPORT

Knowledge, Awareness and Opinion Research

- Public Telephone and Online Survey Results
- Community and Business Leaders Survey Results

July 2011

YUKON ENERGY

Prepared by Aasman Brand Communications and Andrew Hume and Associates Ltd.

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SECTION I
(Public Research)

Introduction

Telephone and online surveys were conducted throughout Yukon communities in January and February 2011 as part of a Phase II research initiative. The overarching intent of this research is to provide the Yukon Energy Corporation with reliable information relative to the knowledge, awareness and views of Yukon residents toward the corporation and current and future energy needs.

The research was also designed to identify the knowledge of Yukoners concerning energy issues and strategic alternatives and actions of Yukon Energy toward achieving a clean, reliable and economically viable energy future.

Several of the survey questions paralleled questions asked in telephone and online surveys conducted in Phase I research (May-June 2010) to identify changes in knowledge, awareness and view of Yukoners concerning energy related issues.

Research Goals:

1. To provide Yukon Energy with reliable information relative to the knowledge, awareness and views of Yukon residents toward the corporation and current and future energy needs.
2. To identify knowledge levels of Yukoners concerning Yukon energy issues and strategic alternatives and actions of Yukon Energy toward a clean, reliable and economically viable energy future.

Research Objectives:

1. To identify changes in knowledge and awareness around key energy needs, issues and experiences.
2. To identify awareness of various information campaign components initiated between Nov. 2010 and Jan. 2011.
3. To identify recall of core messages provided through campaign materials.

Research Methods

A combination of telephone and online surveys and pulse polls were conducted with the Yukon public in communities throughout the Yukon in February-March 2011.

The survey methods covered a range of questions on energy related issues affecting Yukoners.

This report focuses on the results of an online survey and a telephone survey undertaken in early 2011 and compares some (benchmark) responses from telephone and online surveys undertaken in Phase I (May-June 2010).

The online survey was promoted through a communications campaign using traditional and online media and information delivered to Yukon households. An incentive was offered to enhance survey participation.

The telephone survey used a randomized process in selecting individuals in several Yukon communities.

A series of pulse polls were also used. Pulse polls were published in the online edition of the Yukon News and on the Yukon Energy website. This method was designed to gather quick snapshot, top-of-mind responses to a few key issues and formed part of Yukon Energy's public communications initiatives. Pulse polls were also used to promote the online survey. While pulse poll responses are reported, they do not form part of the formal research analysis in assessing current knowledge and awareness.

To achieve an overall confidence level of 95% Yukon Energy wanted to hear from 380 respondents. In total 563 Yukoners responded to the telephone (174) and online (389) surveys. The series of pulse polls received a total of 849 responses.

Respondents by Community

Online Survey
The online survey captured 389 respondents. Eleven Yukon communities participated. Some respondents did not indicate their community of residence. Identified response communities included:

Whitehorse:	303	Carcross:	3	Old Crow:	1
Dawson City:	19	Dest. Bay:	3	Stewart X:	1
Marsh Lk:	14	Mt. Lorne:	3	Rock Cr:	1
Watson Lk:	8	Teslin:	2	Mayo Rd.	1
Mayo:	7	Burwash Ld:	2	Golden Horn:	1
Tagish:	6	Carmacks:	2	Alaska Hwy:	1
Haines Jct:	5	Faro:	2	Unknown:	4

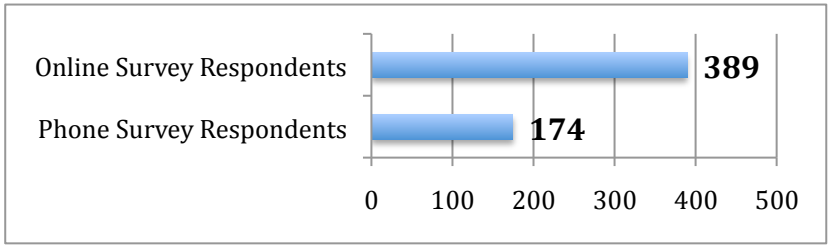
Telephone Survey
The public telephone survey included a randomized sample of 174 Yukon residents from seven communities. Response communities included:

Whitehorse	97
Marsh Lake	27
Dawson City	19
Haines Jct.	10
Carmacks	10
Teslin	10
Ross River	1

Summary of Key Findings

Engagement and Interest in Energy Issues

The overall response rate to the online survey and pulse polls and the willingness to participate in a telephone interview (with a very low decline rate) indicates Yukoners are significantly engaged and interested in energy related issues.



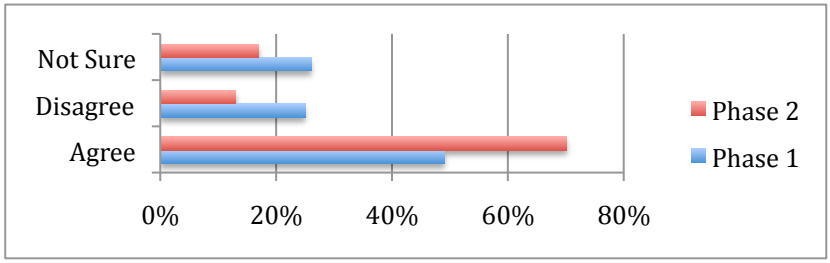
Knowledge/Awareness

Yukoners have a good understanding of energy issues and are aware that strategies are needed to increase production to meet future demands – particularly those of industry that is seen as the big energy consumer.

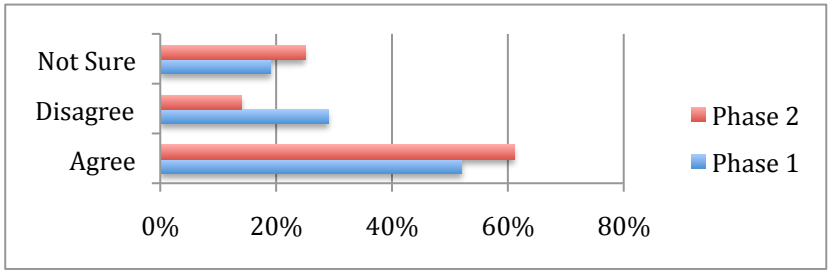
There was an increase in the level of knowledge and awareness around energy issues over the eight-month period between Phase I and Phase II research.

Most Yukoners agreed that power production in the Yukon needs to increase to meet projected future demands and a majority were able to identify some awareness related to a number of Yukon Energy production or system enhancement initiatives.

Do you agreed or disagree with the view that at the current rate of growth Yukon will not have enough energy to meet future needs?

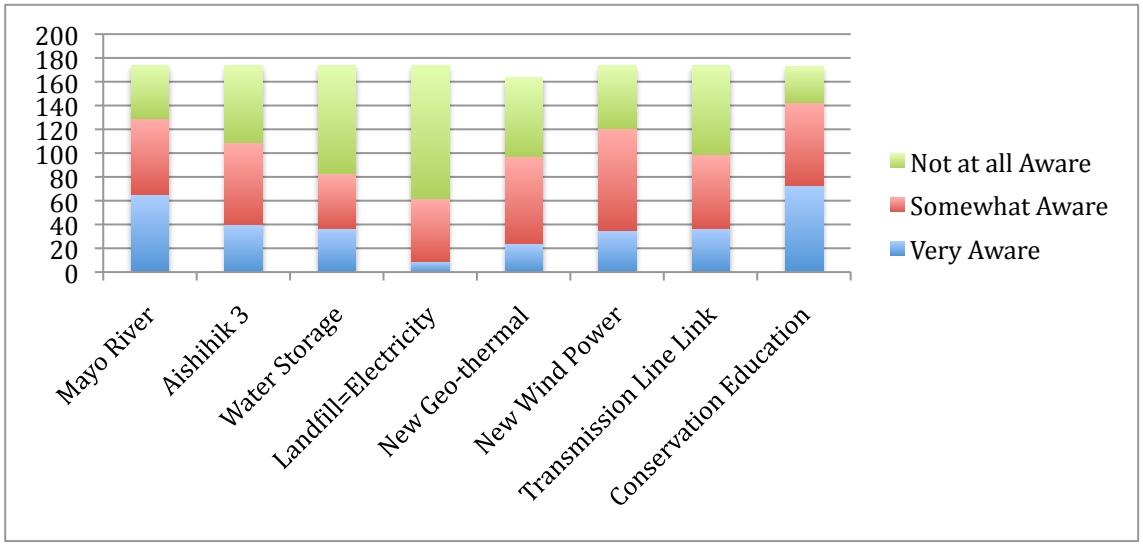


Online Survey



Telephone Survey

Telephone Survey: How aware are you of the following energy development initiatives?



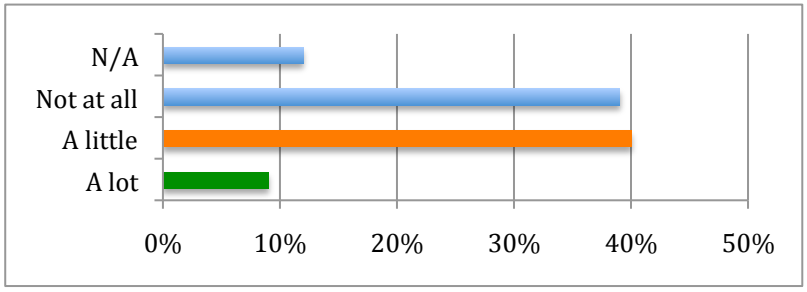
Online survey responses to this question showed a higher level of awareness related to the Mayo River project and to conservation and education initiatives. Low awareness related to the conversion of landfill waste to electricity was evident in both online and telephone survey methods.

Views and Perspectives

Respondents who *have not* changed their views between Phase I and Phase II research periods (39%) indicated it was because they had no new information, or not enough information to influence a change in views. Those who *have* changed their views a little or a lot (49%) said it was because of exposure and access to new information or increased information availability.

Results were consistent between both survey methods.

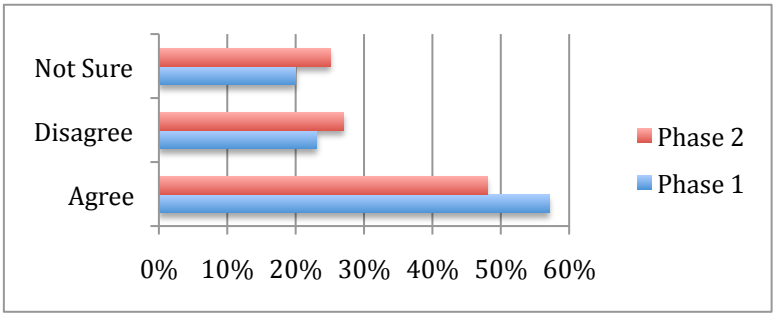
Telephone Survey: Have your views (on energy related issues) changed in the past six months?



Public Confidence

Between Phase I and Phase II, public confidence has declined (from 57% to 48%) on the question of Yukon Energy's ability to *'effectively plan and develop clean energy sources to meet future needs'*.

Telephone and Online Surveys (Phases I and II) combined and averaged response: Do you agree or disagree with the following statement: Yukon Energy has the ability to effectively plan and develop clean energy sources to meet future needs.

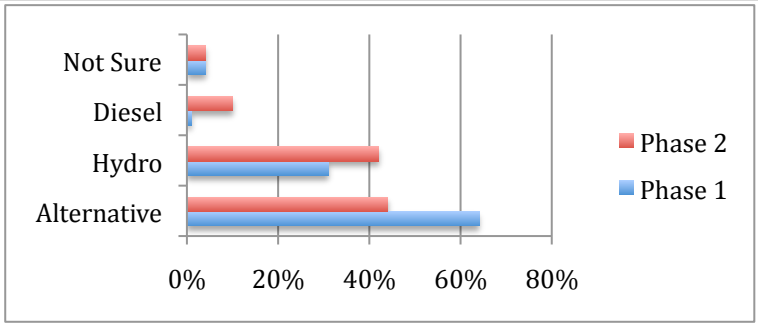


Note: 'Clean energy' was not defined and the reasons or factors affecting the public's views related to confidence were not explored in this research.

Preference for Alternative Energy and Conservation

There is a strong view among Yukoners that alternative energy is important from both an environmental perspective and to diversify capacity to meet future demands. Many feel Yukon could be a leader in alternative energy development and that greater conservation measures need to be taken. At the same time, there is an increasing view that alternatively produced energy may need to be supplemented with hydro generated energy.

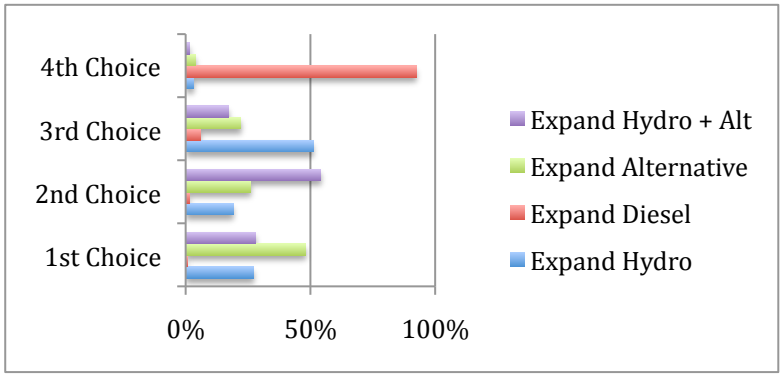
Telephone Survey: If you could choose where your energy comes from what would be your preferred source?



With telephone survey respondents there has been a leveling of support between alternative and hydro as a preferred choice for power generation when comparing the Phase I and Phase II surveys. Phase I survey respondents clearly favor alternative energy over hydro while the Phase II responses show a much closer balance between alternative and hydro. This may be attributed to increasing awareness of the overall future capacity that will be needed relative to the ability to meet this capacity through alternative energy alone.

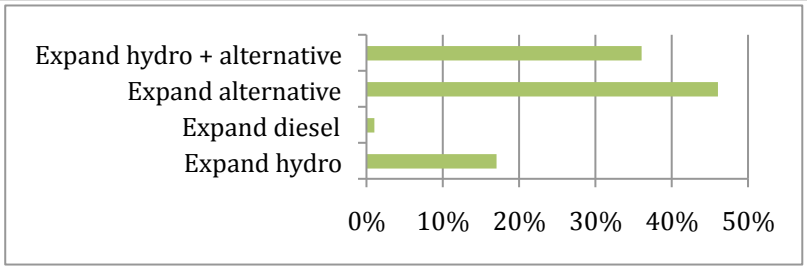
The Phase II online survey, using a ranking option, shows strong support for expanding alternative energy and for a combined alternative/hydro approach.

Online Survey: Indicate your choice preferences regarding expanding energy sources.



In addition to the telephone and online surveys a series of 'pulse polls' were published in the online edition of the Yukon News and on the Yukon Energy website allowing readers to cast a ballot on a specific question. The pulse poll on preferred energy sources reinforced the publics' views on developing alternative energy sources (as well as pursuing a combined hydro/alternative approach).

Pulse Poll: What is your #1 preference for future energy production? (362 votes)

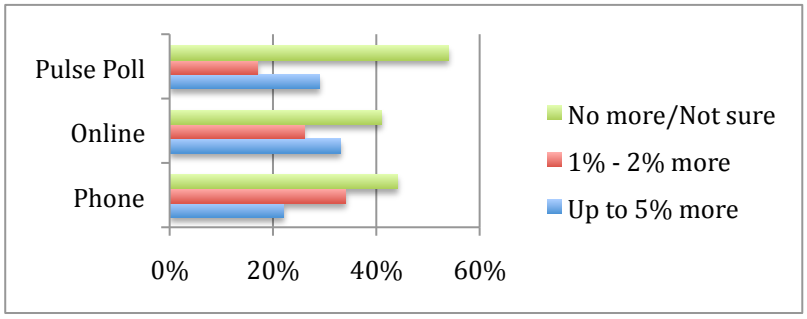


Willingness to Pay for Alternative Sourced Energy

While there were differences in responses between the telephone and online surveys on the question of the willingness to pay more for electricity if it is generated from an alternate source such as wind or geo-thermal, the majority of Yukoners said they would pay more for alternatively produced energy.

With the pulse poll question, a majority said they would not be willing to pay any more than what they are paying now.

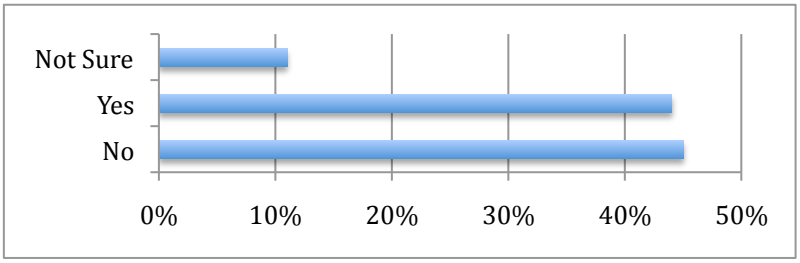
Telephone/Online/Pulse Poll results: Willingness to pay more for alternatively sourced energy.



Communications and Awareness

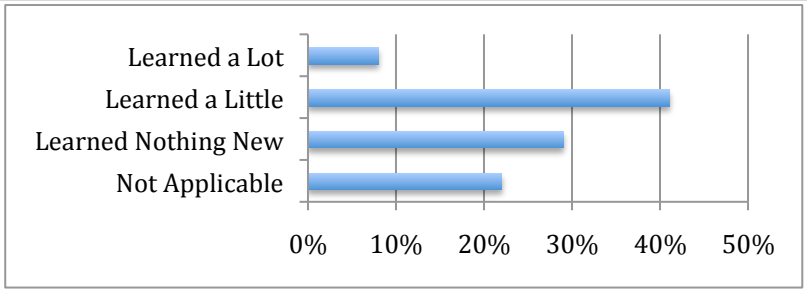
Recent communications initiatives undertaken by Yukon Energy show that an equal number of those surveyed recalled seeing communications material (advertising or household mailer) as those who did not recall seeing information sponsored by Yukon Energy.

Combined and Averaged Telephone/Online Surveys: Do you recall seeing sponsored advertising or a household mailer from Yukon Energy on energy issues?



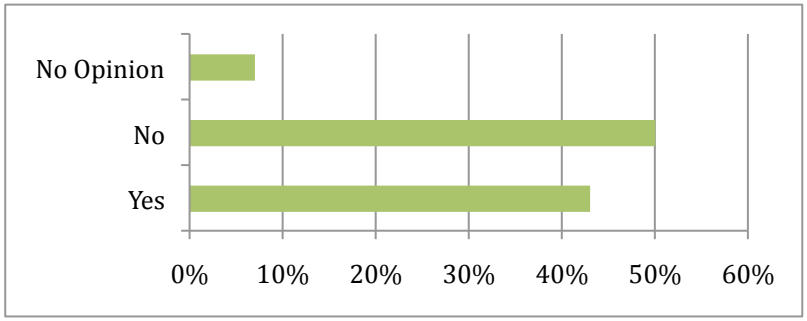
When Yukoners were asked if their knowledge and awareness have increased over the past six months, half (49%) said they have learned a little or a lot.

Combined Results from Telephone and Online Surveys: In the past six months, have you learned a little, a lot or nothing new about Yukon energy issues?



(Note: The knowledge question was asked in the context of Yukon Energy's communications initiatives. The Not Applicable response refers to those who said they couldn't recall seeing information materials provided by Yukon Energy or who declined to answer the question)

Pulse Poll result: Do you know more about Yukon's power issues today than 6 months ago? (166 votes)



Both the telephone and online survey methods provided an opportunity for respondents to provide additional comments related to key issues.

Desire for Change

- From online survey respondents, there were about twice as many comments that reflect a general opposition to the way things are today with respect to energy supply, demand and production issues (particularly the use of diesel for power generation).

- Comments supporting change focused on a concern that current planning is not going to meet future demand. Some discontent also stems from the frequency of power outages.

- Many expressed comments supporting hydro as the right way to go in meeting current and future needs. A noted previously, there is strong support for a combined alternative/hydro approach as well as continuing support for the development of new alternative energy sources and continued conservation and education efforts.

Consumption and Future Demands

- Many respondents are unsupportive of industry's needs and the increasing demand that large industry places on energy consumption and the perceived impact this has on the cost of power to residential consumers.

- There is a perception industry is not paying fairly (i.e. paying below-cost for their power). There is also a perception that industry is a higher priority than Yukon residents. Some respondents said industry should be made entirely responsible for producing and paying for the energy it needs. There is a concern that as new industry and large-scale developments comes on-line, demands for power will increase significantly.

SECTION II
(Community and Business Leaders Research)

Introduction

Between April 20 and May 6, 2011, a total of 54 business and community leaders were invited to participate in a survey on energy issues in the Yukon. A total of 42 people (79%) responded to the survey invitation.

This data complements a similar survey of 41 community and business leaders conducted in July 7-15, 2010. For comparative analysis where the same question was asked in both research phases, the findings are shown as Phase I (July 2010) and Phase II (April/May 2011).

In addition to the core benchmark questions included in the Phase I survey, the Phase II survey included several supplementary questions related to a willingness to pay more for power generated from alternative energy sources and awareness of current Yukon Energy projects and programs.

Research Goals

- To provide the Yukon Energy with current knowledge, awareness and views among Yukon business and community leaders toward the corporation and current and future energy needs.
- To compare any changes in knowledge, awareness and views over the period from July 2010 to May 2011.

Research Objectives

- To establish baseline knowledge, awareness and views
- To assess change in knowledge, awareness and views over time
- To inform the design and development of communications initiatives targeted to community and business leaders regarding Yukon Energy's planning, priorities and actions

Research Methods

The survey was sent by email to community and business leaders in the communities of Whitehorse, Carcross, Burwash Landing, Haines Junction, Mayo and Carmacks. Ninety percent of respondents identified themselves as living/working in Whitehorse. The remaining 10% were from Haines Junction and Destruction Bay/Burwash Landing.

The majority (61%) of respondents to the Phase II survey self-identified as coming from the private sector, balanced by those from the public or community sector or an advocacy based organization.

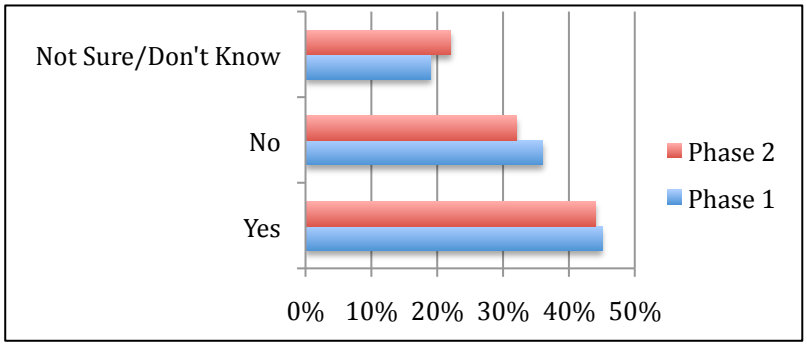
The survey included telephone interviews and an online survey with corresponding questions used in each method. For respondents who preferred to be interviewed on the telephone, their responses were captured in the same format as the online survey.

Confidence Indicators

The level of confidence among community and business leaders in Yukon Energy's ability to *'assess Yukon's future energy needs' increased* from 62% to 85% over the past 10 months.

Over the same time, the level of confidence in the corporation's ability to *'plan and develop clean energy sources to meet future demands'* remains unchanged at approximately 45%. Just over 20% remain unsure of their level of confidence on this question.

Do you have confidence in Yukon Energy to plan and develop clean energy sources to meet future demands?

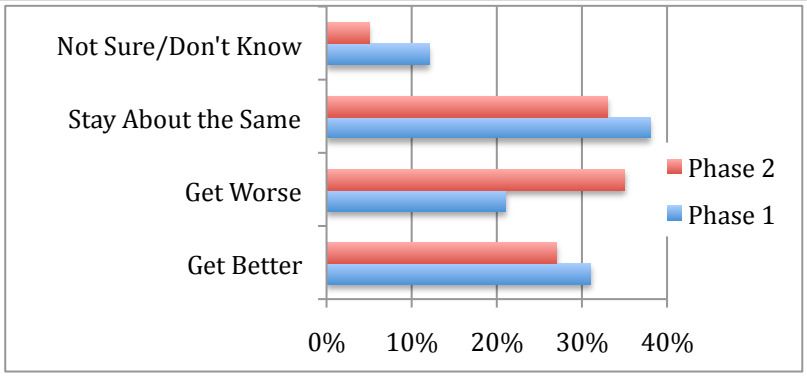


Past Experience and Confidence in Future Reliability of Power Supply

The survey asked respondents to think retrospectively over the past 12 months in terms of their past experience with energy supply issues as well as consider their relative confidence in the future reliability in the supply of power over the next five years.

Business and community leaders expect the availability of power supplies to get worse over the next five years. This shows a negative shift in confidence related to future reliability from 21% of Phase I survey respondents saying reliability will get worse, to 35% of Phase II respondents expecting supply reliability to worsen.

Expected reliability in the power supply over the next 5 years:



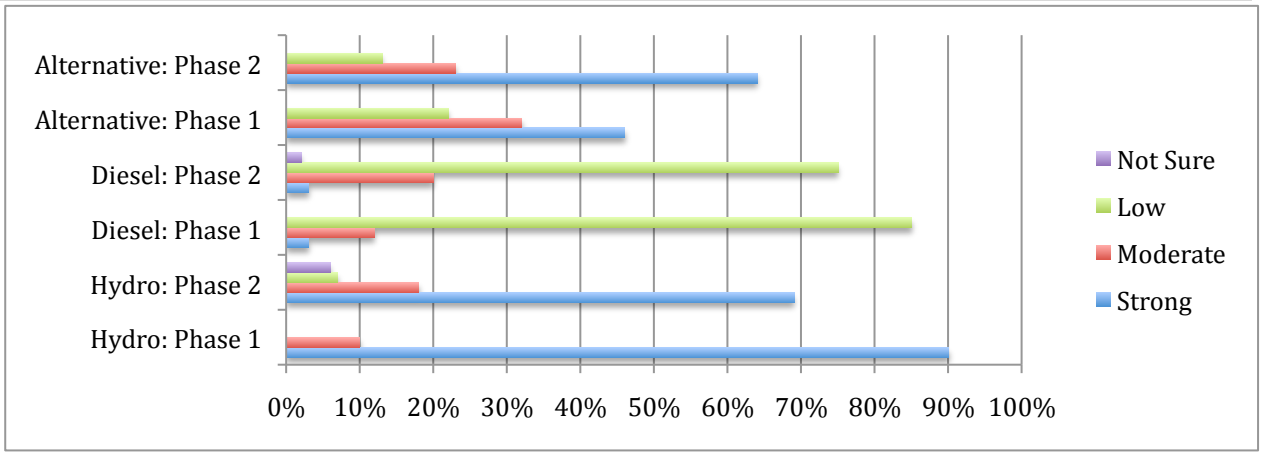
Support for Alternative Sourced Energy

Responses over the two research periods show a decline in strong support for hydro and increased support for alternative sources. Support for the continued development of alternative energy sources in combination with new hydro sources was identified by just over three-quarters (77%) of respondents as a first or second choice preferred option for meeting future energy needs in a Phase II optional question.

(Note: The 'Hydro + Alternative' response is not shown in the chart below as the question was asked as an additional option in Phase II research).

A very low level of support for diesel-sourced power remained consistent between both research periods. There was an increase in the level of 'moderate' support for diesel in Phase II responses. This may be related to those who expect supply reliability to worsen over the next five years and see a continued need for back-up diesel generated power until overall capacity from other sources is increased.

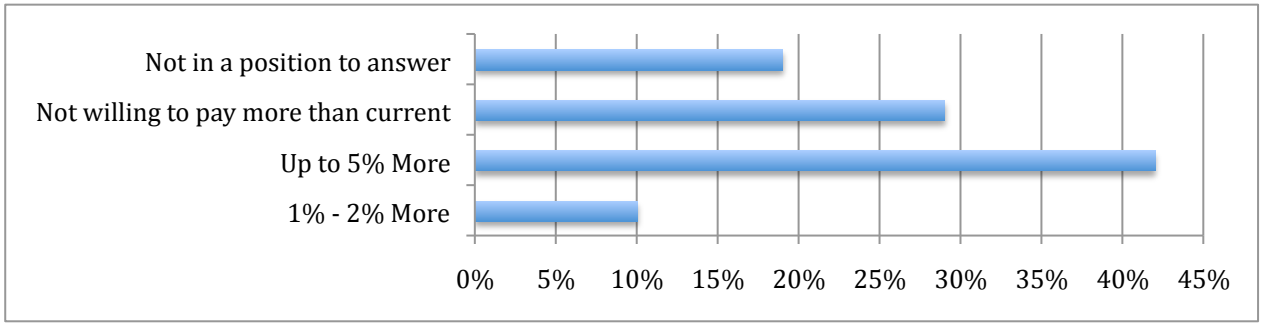
What level of support do you give each of the following power generation options?



Willingness to Pay More for Alternative Sourced Energy

Just over half of respondents (52%) said they would be willing to pay more for electricity produced from alternative sources ranging from 10% who said they would pay 1%-2% more and 42% who indicated a willingness to pay up to 5% more. This indicates support for the continued development of alternative sourced energy as well as an understanding that these technologies will cost more to design, develop and bring on-line.

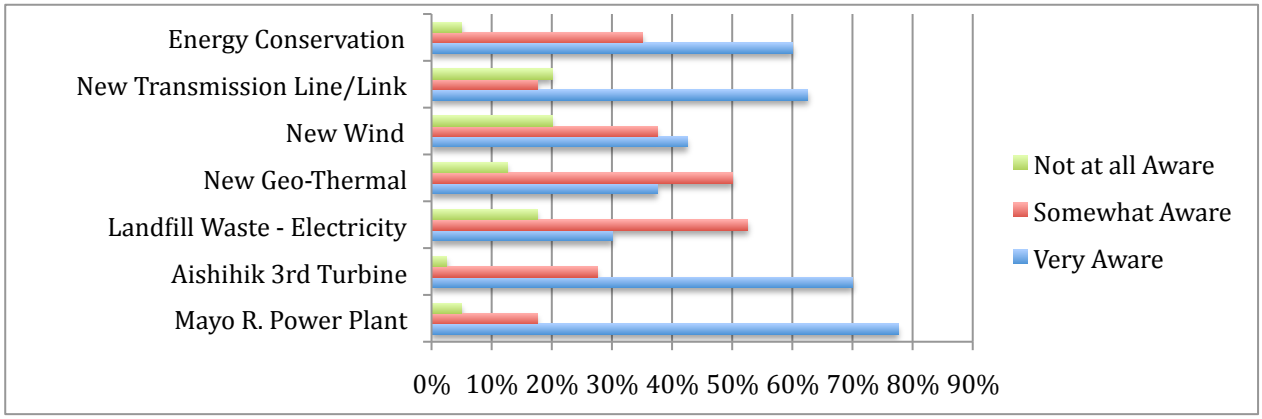
Thinking about your company or organization, are you willing to pay more for electricity if it is generated from an alternative source such as wind or geo-thermal?



Awareness of Yukon Energy Projects

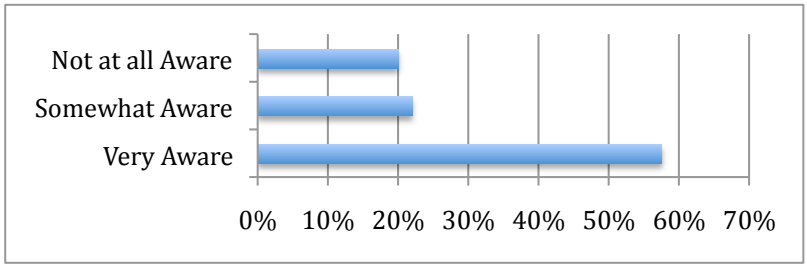
The Mayo River power plant and third turbine at Aishihik show a high awareness followed closely by the new transmission line link and energy conservation measures. Wind-based energy shows a reasonably strong awareness with 42% indicating high awareness and 38% somewhat aware. Geo-thermal energy sources and converting landfill waste to electricity show the lowest awareness levels.

How aware are you of the following Yukon Energy projects?



A question related to water storage planning being undertaken by Yukon Energy shows that almost 60% are Very Aware and just over 20% Somewhat Aware of this initiative

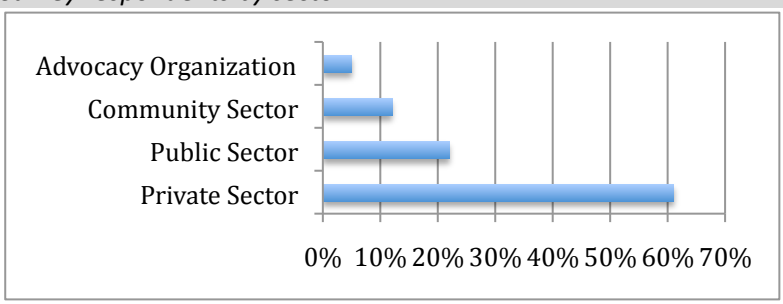
To help meet peak power demands in the winter when water levels are low, Yukon Energy is exploring ways to store more water in the Atlin, Marsh and Gladstone Lakes systems. How aware are you of Yukon Energy's research and planning for increased water storage?



Sector Response

A majority of respondents to the community and business leaders survey identified themselves as being associated with the private sector, followed by the public and community sectors. Several respondents identified association with an advocacy-based organization.

Survey respondents by sector:



Summary of Comments
About 80% of respondents for the survey took the time to write a comment outlining concerns, ideas and observations about Yukon Energy and related energy issues and priorities. This type and level of response reflects a highly interested target group.

A review of responses indicates the following key points of interest and concerns:

- **Education and Communication**
  The public, business, industry and interest groups need to know more about what is needed to meet current and future energy needs, what is being planned and when new energy sources will come on line.

- **Conservation and Incentives**
  There is a strong desire to enhance energy conservation efforts through education as well as by providing incentives for individuals and families, business and industry to participate in energy conservation efforts. The availability of funding help through small grants and loans to enable participation in energy conservation (such as energy retrofits etc.) was also noted. Both industry and political leaders are seen as being important in creating a climate for positive change.

- **Evidence-based Costing**
  Professional energy audits of buildings and operations resulting in clear options and quantifiable benefits derived through energy conservation was noted along with the need to use new technologies such as smart meters to be able to assess variable costs based on time-of-day usage.

  In keeping with the conservation and education theme, several respondents commented on the need to make people more aware of peak usage times of day and encourage more off-peak usage. Comments also reflected a need to design and provide incentives (such as rebates) for those who actively demonstrate conservation measures.

- **Alternative Sourced Energy**
  Consistent with overall survey responses, there continues to be an underlying theme of support for the development of alternative sourced energy as a way to supplement the overall supply of power.

Note: The length of residency of respondents to was consistent between Phase I and Phase II research with a strong majority being resident in the Yukon for over 20 years. The second highest group (at 10%) indicated they have been a Yukon resident for one-to-five years.

Yukon Energy Corporation

Public and Stakeholder Phone Survey Results
Public Awareness Campaign Phase 1:
Research Report 1

Prepared by
Andrew Hume and Associates Ltd.
In association with Aasman Brand Communications

June 25, 2010

aasman
branding on purpose

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Introduction

The research component of the public awareness campaign was developed to establish benchmark indicators among target audiences to assess and evaluate knowledge of Yukon Energy and awareness of energy related issues.

The research model was built in a knowledge, awareness, and behaviour (KAB) evaluation design. KAB essentially begins by testing current knowledge levels, assesses any change in awareness levels over time (ie: as a result of an educational or communications intervention) and finally whether any increase in knowledge and awareness or change in beliefs and expectations.

Two audience groups are targeted in this research:

1. Allies: Allies include businesses and associations, community organizations, First Nations, governments, and other groups who have a vested interest in supporting a long-term clean energy strategy for the territory. By understanding the vision and strategy of Yukon, this audience will be more inclined to envision a positive investment future in Yukon resulting in economically stronger communities.

   This audience also includes potential allies-Yukon politicians, the Yukon Conservation Society, the Utilities Consumer Group, the Yukon Utilities Board, and others.

2. Public Audience: This audience is comprised of all Yukoners who use or have an interest in electrical energy. Typically, this audience is predisposed to renewable sources of energy versus fossil fuel sources of energy for both cost and environmental reasons.

A **Public telephone survey** was conducted with 184 randomly selected respondents in six Yukon communities between June 2 – 8, 2010 involving a 10-15 minute interview covering a range of questions on the Yukon Energy Corporation and energy related issues.

The six communities selected for the public phone survey included: Whitehorse; Marsh Lake; Teslin; Carmacks; Haines Junction; and Dawson City.

An **Allies telephone survey** involving 25 business and community leaders and interest groups was conducted between June 4 – 11, 2010. The survey recipients were selected to provide a cross sample of individual businesses, Yukon-wide associations and local community leaders. Communities included: Whitehorse; Mayo; Faro; Watson Lake; Haines Junction.

Both phone surveys were conducted prior to the launch of the public awareness campaign.

In addition to the telephone surveys an **online public survey** is also being conducted over a 4-6 week period (June 15 – June 30, 2010). The online survey is being conducted in conjunction with the campaign with participation promoted through the campaign as well as on the Yukon Energy Corporation's website.

Research

Research Goals

- To provide the Yukon Energy Corporation with current Knowledge, Awareness and Behaviour (KAB) among Yukon residents and business and community leaders toward the corporation and current and future energy needs

- To build a renewed sense of trust and confidence among Yukon residents in the corporation supporting its vision of a clean energy future

Research Objectives

- To establish baseline KAB data
- To acquire research support to effectively position the Yukon Energy Corporation and its vision for a clean energy future
- To inform public communications initiatives undertaken by the Yukon Energy Corporation
- To test effectiveness of communications, information and messaging

Research Targets

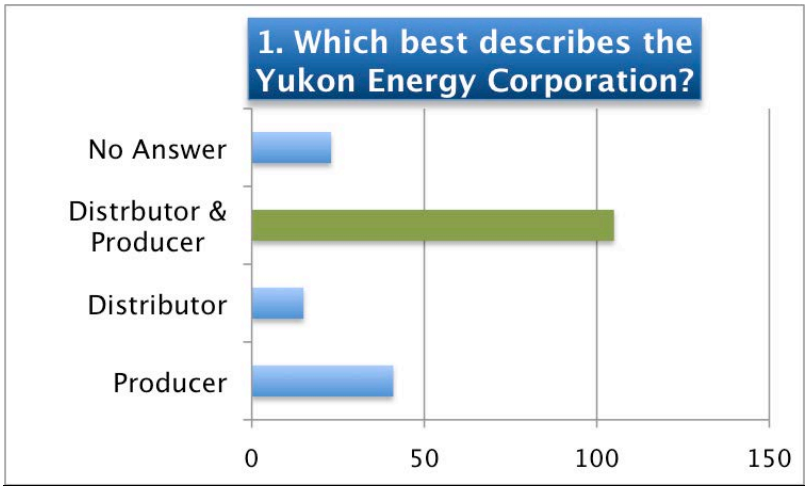
To achieve a confidence level of 95% an overall target for all methodologies is 380 respondents. The combined participation from both telephone surveys is 209 (public phone survey: 184; stakeholders phone survey: 25). The online survey will deliver the remaining responses.

Following are the findings of the public and stakeholders phone surveys.

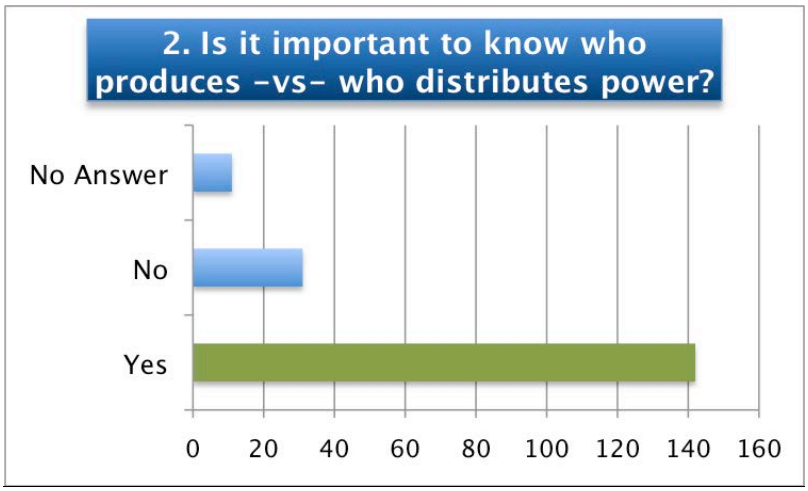
Public Telephone Survey Findings

The majority of Yukon residents are aware the Yukon Energy Corporation is both a producer and distributor of electrical power.

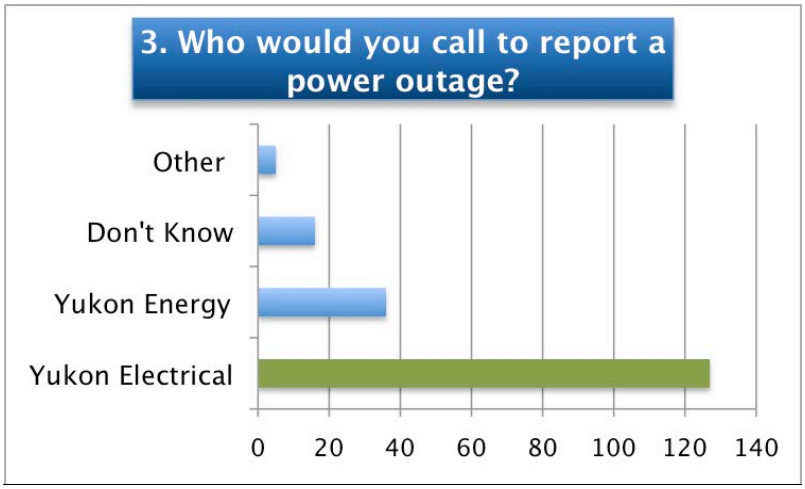
However a significant number are not aware of the dual responsibility of the corporation with regard to the production and distribution of electrical power as indicated by those who said the corporation was only a producer or only a distributor or did not know.



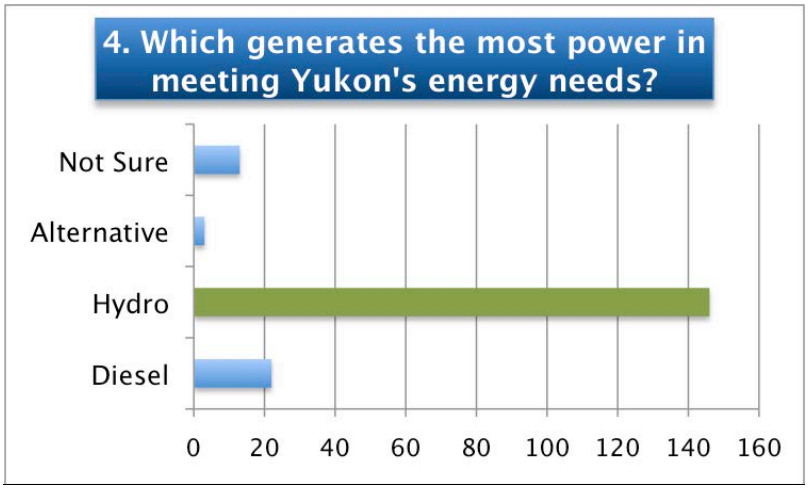
A strong majority of respondents said it is important for them to know who produces and who distributes power.



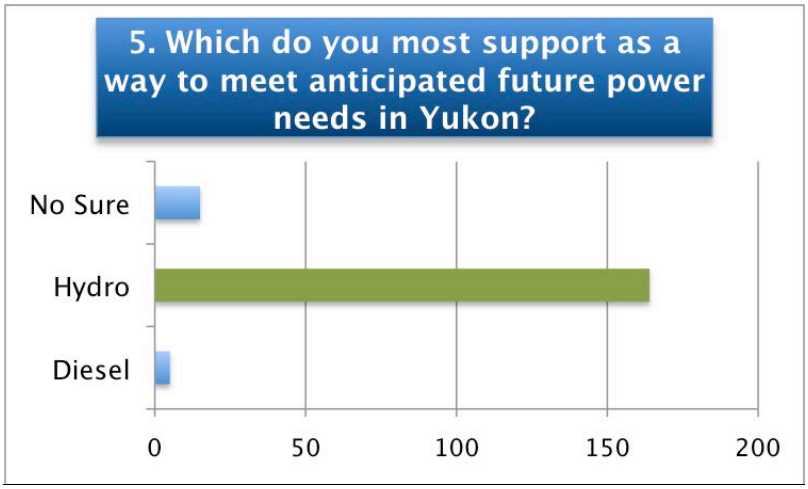
In terms of who residents would call if they experienced a power outage, a strong majority said they would call Yukon Electrical as the primary power provider. In looking at community variations on this question, responses ranged from a low of 25% (Dawson City) who said Yukon Electric would be their first point of contact to a high of 80% of residents (Carmacks and Haines Junction) who would call Yukon Electric first. Over three-quarters (76%) of Whitehorse residents identified Yukon Electric as a first contact point.



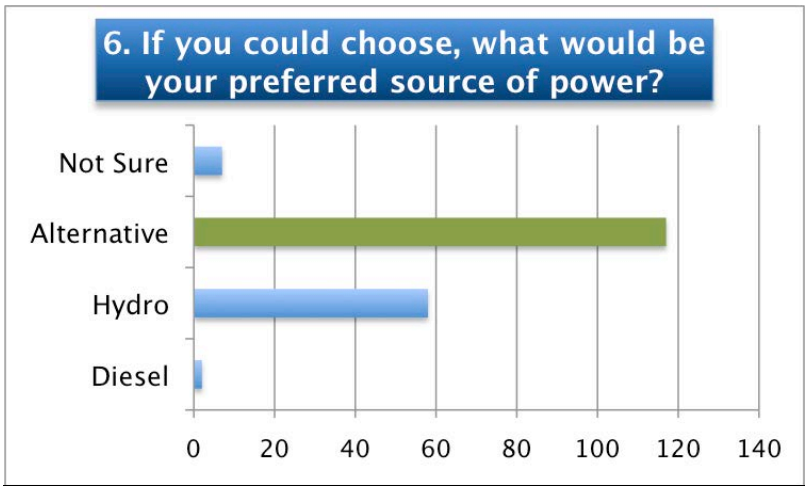
A strong majority of Yukon residents are aware that Yukon's power is primarily hydro generated. This is consistent across all communities surveyed.



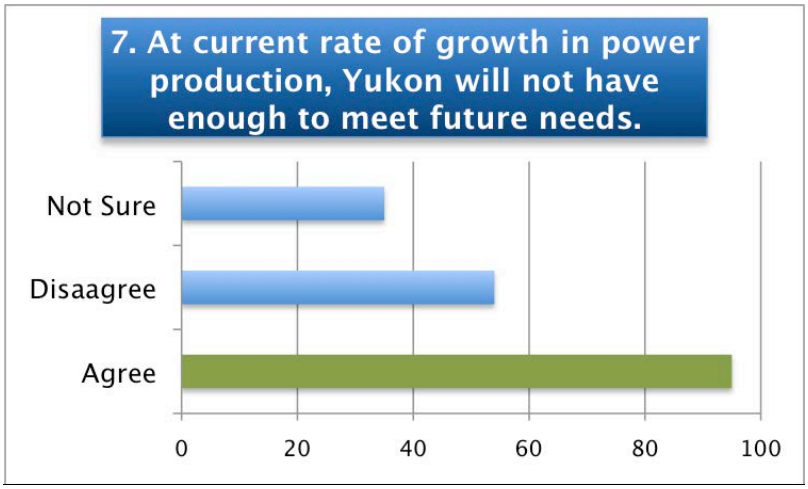
Hydro generated power is clearly a preferred alternative to diesel-generated power across all communities.



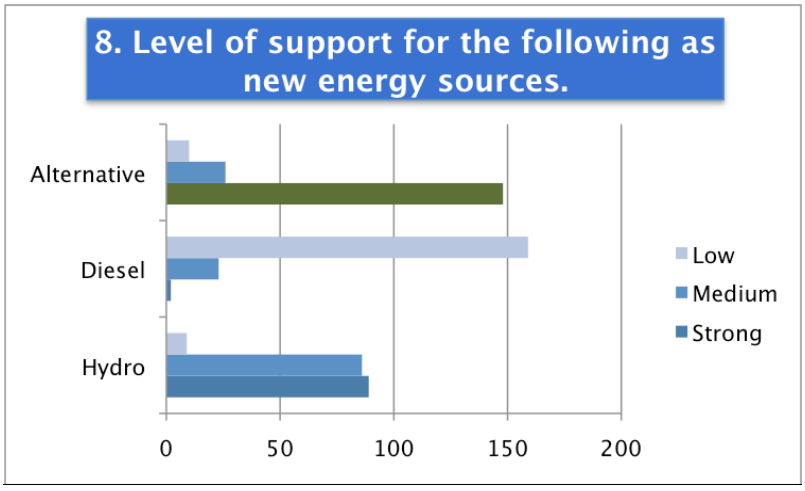
The phone survey identified a strong preference for the development of alternative energy sources. 'Alternative' was described as wind and geo-thermal. Carmacks showed the highest level of support for alternative sources at 70% and residents of Marsh Lake showed the lowest support at 56%. In Whitehorse 65% of respondents identified alternative as preferred source of power.



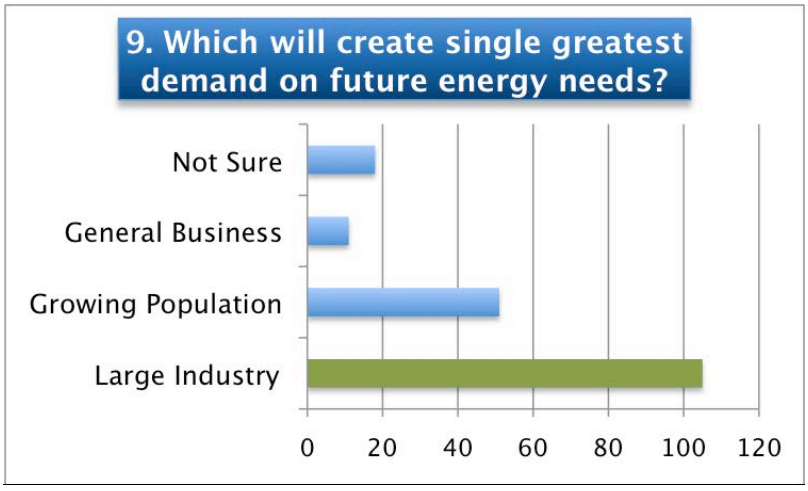
When asked to think about the energy production and future needs, only slightly more than half (52%) of residents agreed that Yukon will not have enough energy to meet future needs. This was relatively consistent across all communities with the exception of Carmacks where 80% of respondents agree with this projection.



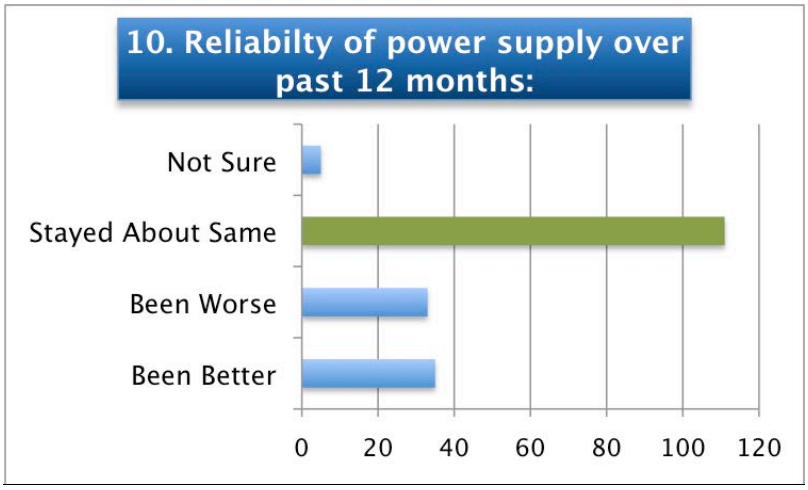
A clear majority of respondents do not support diesel-generated power as a future energy source. Consistent with question #6, the strongest support is indicated for the development of new alternative energy sources followed by hydro which received medium to strong support.



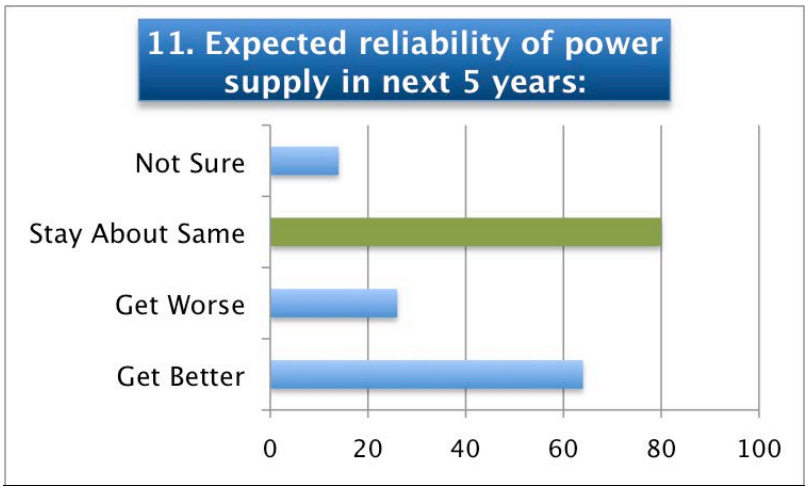
Yukon residents see large scale industry as the big driver in terms of creating the greatest demand for future energy needs followed by population growth (residential consumption). There was however a wide variance in response by different communities to this question ranging from a low of 50% (Dawson City) who see large industry as the biggest future power consumer, to 80% of respondents from Carmacks. In Whitehorse 52% of respondents said they saw large industry as creating the biggest energy demand.



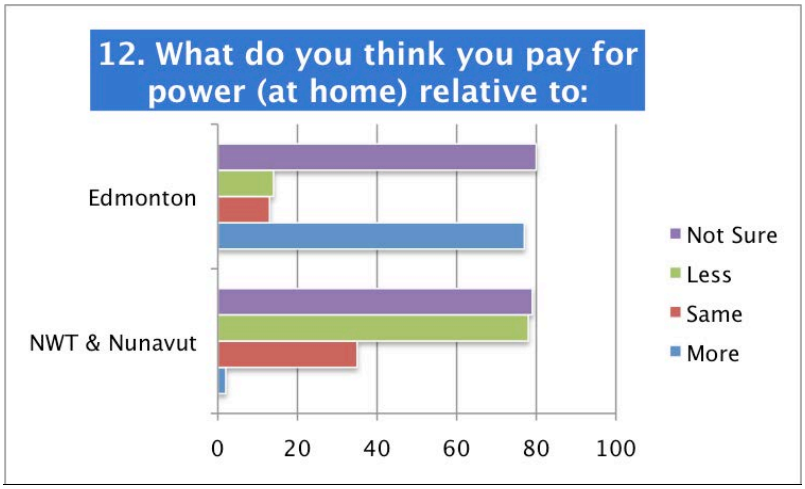
Questions #10 and #11 identified how reliable Yukon residents feel their energy supply has been over the past year and how reliable they think it will be over the next five years. The majority of respondents feel there has been little change in reliability over the past 12 months or that reliability has improved. Responses varied marginally by community with most in the 75%+ range in saying reliability has been better or the same.



In the context of their recent experience (past 12 months) the majority of Yukon residents (78%) feel the reliability of power over the next five years is likely to remain unchanged or get better.



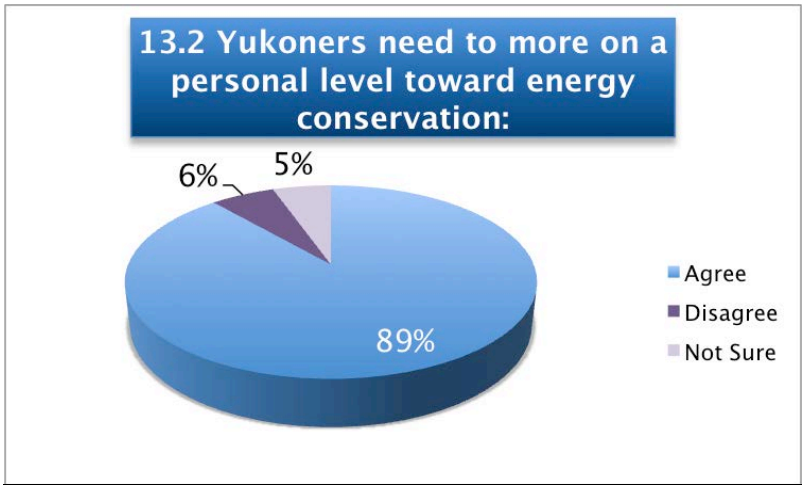
Using Nunavaut/NWT and Edmonton for comparison, survey respondents were asked to indicate if they felt they paid more, less or the same for power. While Yukon residents feel they pay less or are not sure in relation to other northern residents they clearly feel they pay more than residents of Edmonton. Forty-four per cent (44%) of respondents said they were not sure.



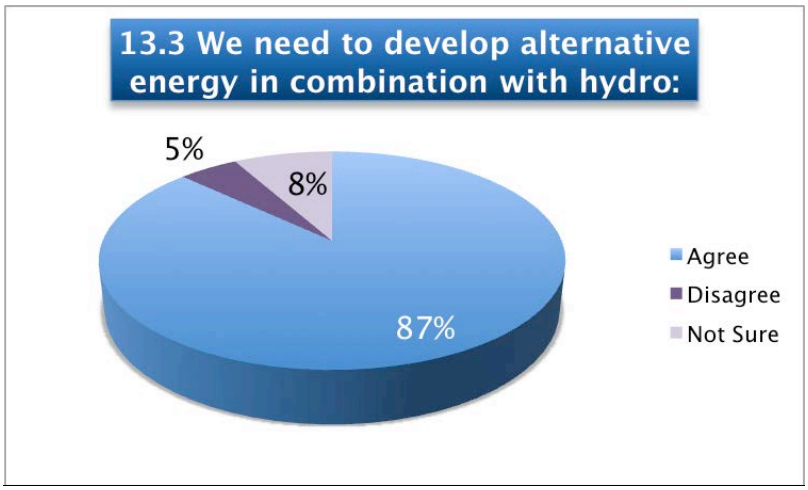
On the question of confidence in the Yukon Energy Corporation related to planning and developing clean energy sources to meet future needs, 58% said they had confidence in the corporation. The level of confidence ranged from a low of 30% in Haines Junction to a high of 80% in Carmacks. In Whitehorse 62% said they have confidence in the corporation.



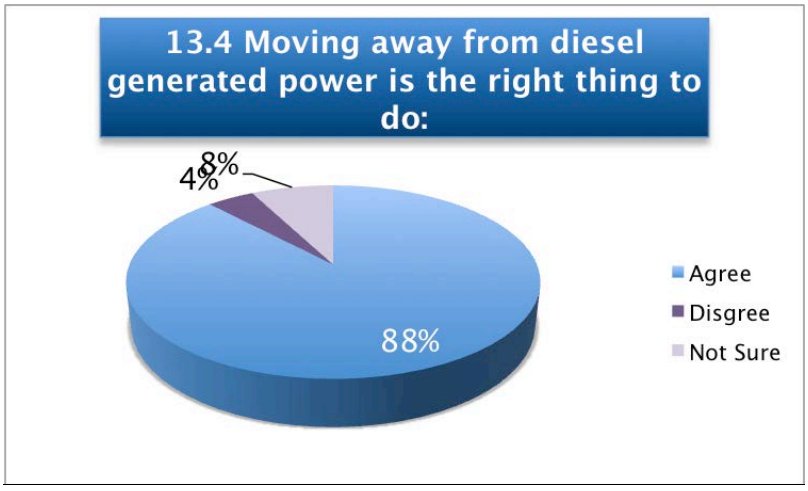
On the question of Yukoners assuming more personal responsibility toward energy conservation, 89% are in agreement.



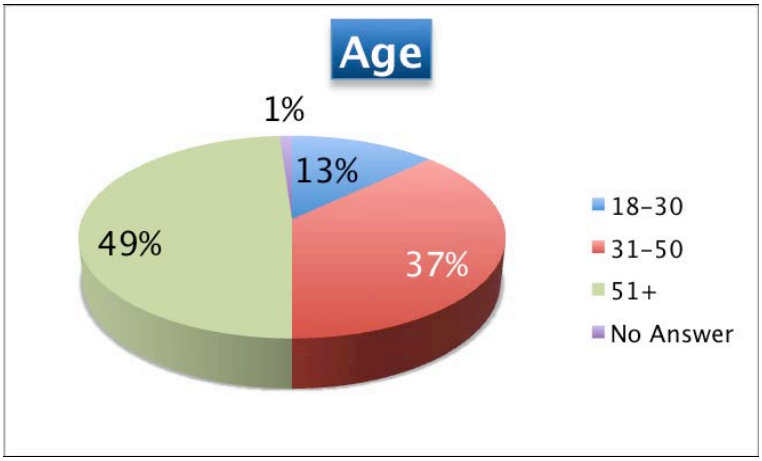
An equally high number (87%) of respondents agreed with a planning approach that would see new alternative energy sources developed in conjunction with hydro development to meet future needs.

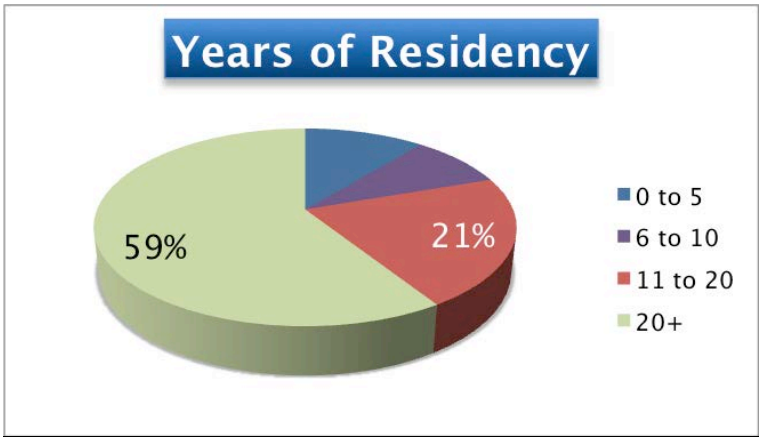


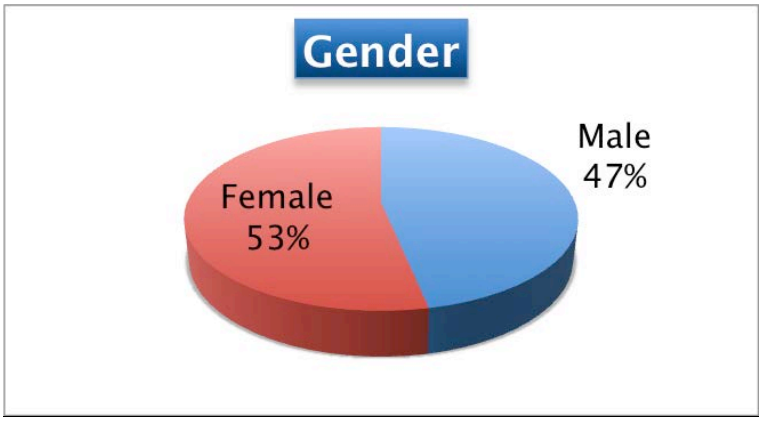
A strong majority (88%) reinforced their support for alternative and hydro by saying the Yukon needs to move away from diesel-generated power. Support for moving away from diesel-generated power ranged from a low of 70% in Haines Junction to a high of 90% in Whitehorse and Dawson City.



Almost half (49%) of respondents were 51 years or older with over a one-third (37%) in the 31 to 50 year age group. The majority of respondents were also longer-term residents with 59% indicating 20 or more years of residency. Gender of respondents was relatively evenly divided.

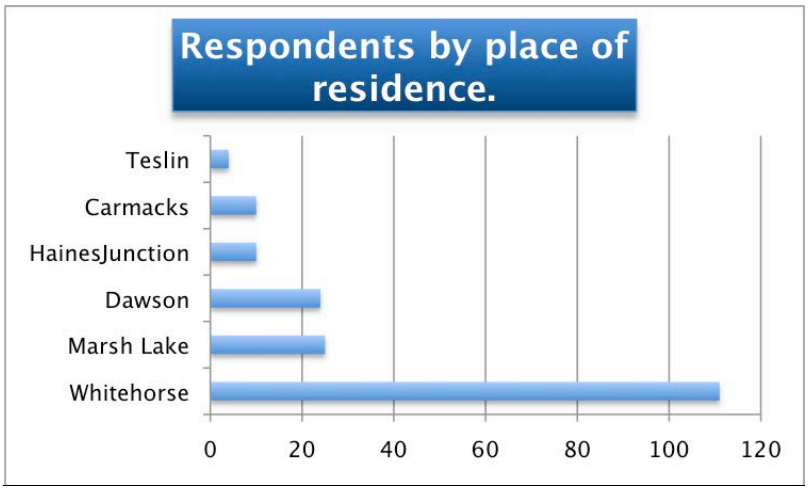






Sixty percent of respondents (111) were surveyed in Whitehorse with 25 residents in Marsh Lake and Dawson City participating in the survey. For the smaller communities of Haines Junction and Carmacks 10 phone surveys were done in each community. In Teslin four surveys were conducted.

> Note: It is important to note that the sample size in communities outside Whitehorse is not significant enough from which any conclusions can be drawn with any degree of confidence at an individual community level. The data was provided on a community-basis for some questions as a point of interest only.



Findings from the stakeholder telephone survey can be found the following section.

BUSINESS AND COMMUNITY LEADERS (ALLIES) PHONE SURVEY FINDINGS

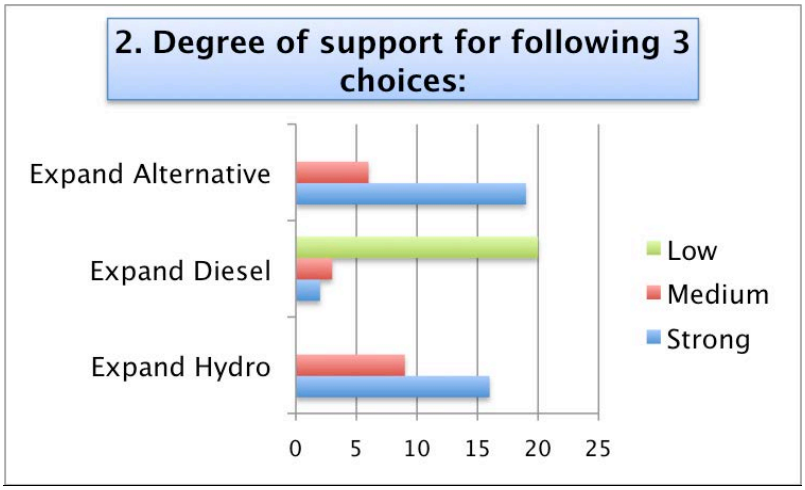
Introduction

A telephone survey involved 25 business and community leaders representing a cross sample of businesses, Yukon-wide associations and local community leaders.

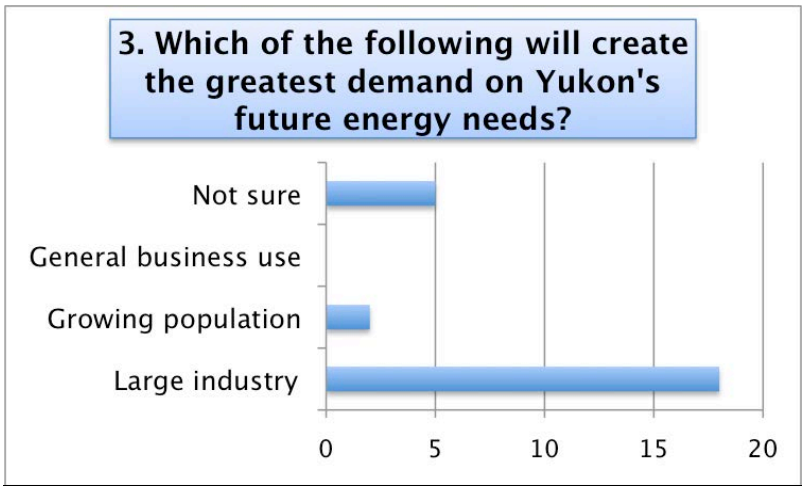
Yukon business and community leaders indicate a high degree of confidence (88%) in the Yukon Energy Corporations' assessment that new energy sources will be needed within the next five years in order to meet future demands.



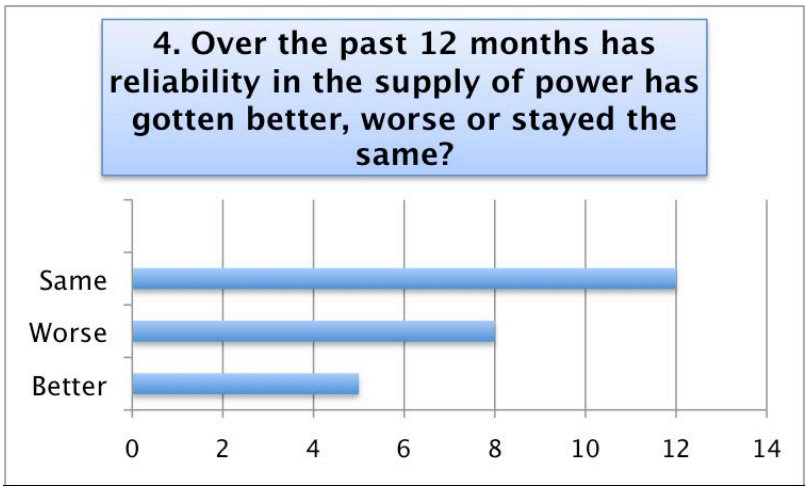
Business and community leaders indicate a strong preference for alternative energy followed by hydro development. Support for diesel-generated power is very low.



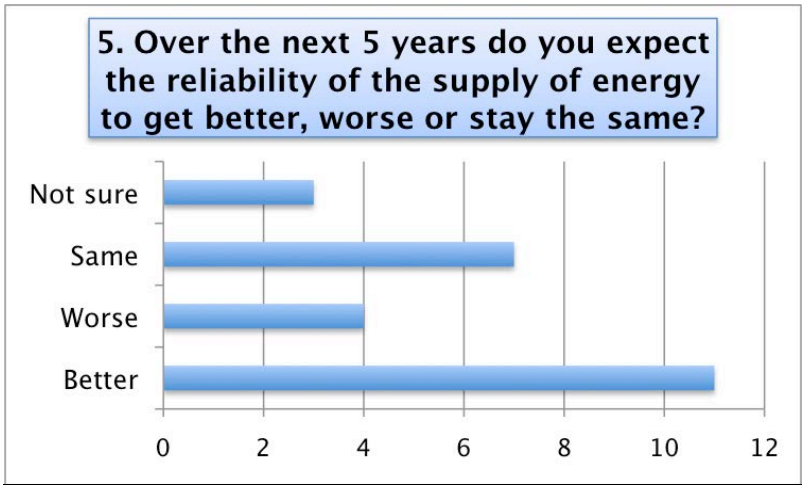
Consistent with the public phone survey, business and community leaders believe large industry will be a primary driver in future energy demands.



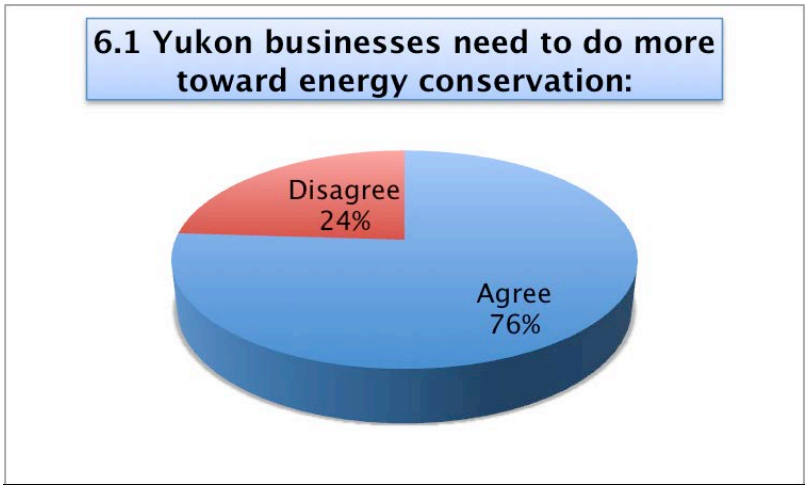
Approximately one-third of business and community leaders feel energy reliability worsened over the past 12 months as compared to about 18% of public survey respondents.



In terms of expected reliability over the next five years, business and community leaders feel more confident with almost half expecting reliability to improve and only 16% expecting reliability to get worse and over one-quarter (28%) expecting no change.

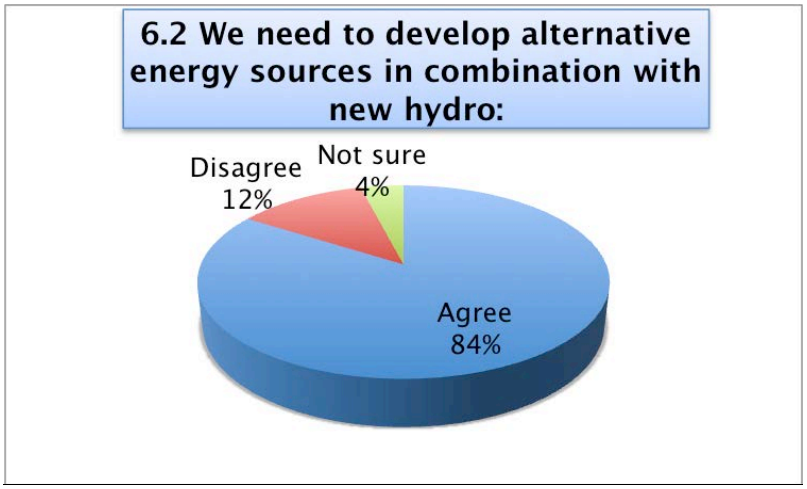


Over three-quarters (76%) of business and community leaders feel Yukon businesses need to do more toward energy conservation. While this is a strong indicator that businesses feel the need to assume greater responsibility for conservation, the public's sense of personal responsibility is much higher at 89%.

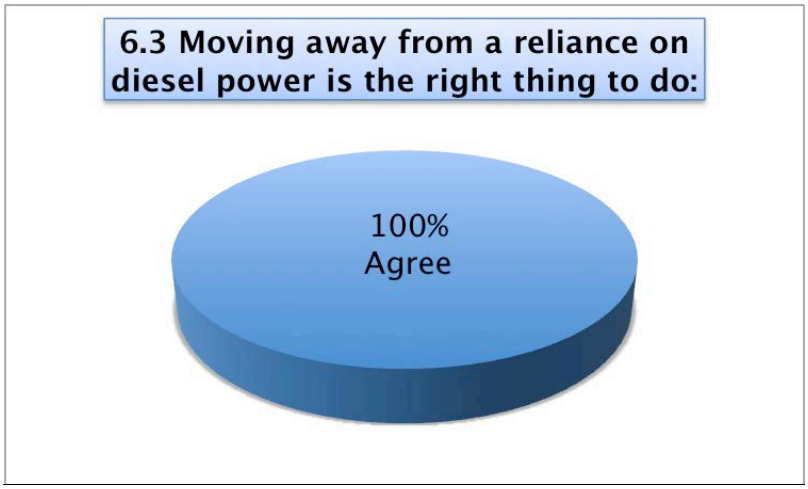


Comments related to this question indicate that conservations is a 'shared responsibility' across all sectors.

There is a high degree of support (84%) among business and community leaders for the development of alternative energy sources in combination with hydro. Alternative energy also received strong support from the general public.

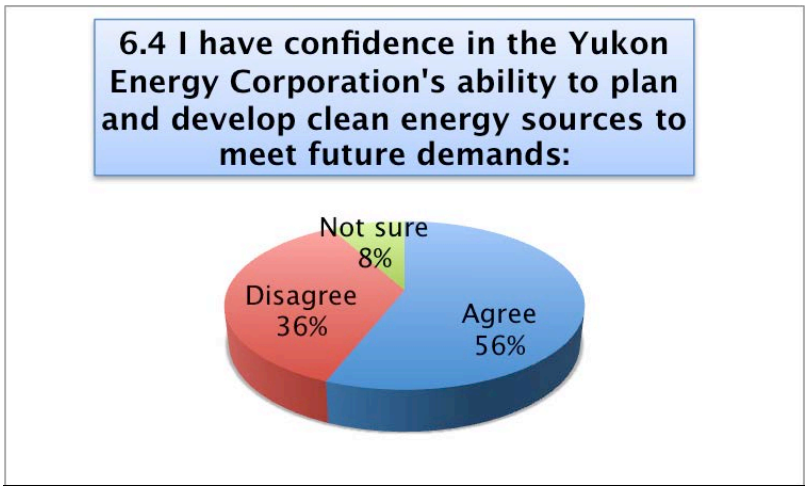


Also consistent with the public's view, business and community leaders strongly believe that moving away from a reliance on diesel-generated power is the right goal for the Yukon Energy Corporation to be pursuing.



Additional comments suggested that multiple alternative sources need to be further explored including things like bio-fuels and waste-energy in addition to hydro, wind and geo-thermal and natural gas should also considered. Some suggest the corporation lacks creativity with respect to new clean energy sources and opportunities.

While a strong majority (84%) believe the Yukon Energy Corporation should be developing clean energy sources (see Q. 6.2), just over half (56%) of business and community leaders have confidence in the corporation's ability to effectively plan and develop clean energy.



Additional comments included:

- Political influence and interference with the Yukon energy sector affects productivity and the ability to plan effectively. (Several mentions)
- Responding to external opposition and special interest groups interferes with effective planning.
- Years of opportunity to develop new clean energy sources have yielded little results.
- Reliability and cost need to be considered when developing alternative energy sources.
- Investment needs to be made in Yukon's power distribution system.
- Open up power generation to enable third parties to be become involved.
- The corporation needs to do more public consultation (this survey was a good start).
- Lack of a strategic plan and cost-benefit analysis.
- Lack of talk related to encouraging energy conservation.
- Important to plan and develop now to meet future needs and not get caught energy short. (Yukon Energy Corporation appears to be doing a good job projecting what future needs will be).
- More communication is needed on energy issues and options.

General Service

Lighting Redesign and Equipment Incentive – *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 31-33/)*

Exhibit 1: Participation Projections – Lighting Redesign and Custom Lighting Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM91	Lighting Redesign Study	9,181 ft2	50,876 ft2	83,390 ft2	83,390 ft2	41,695 ft2	268,531 ft2
ECM80	Typical Lighting Project in	0 ft2	11,738 ft2	31,786 ft2	36,327 ft2	36,327 ft2	116,179 ft2
ECM81	Typical Lighting Project in Existing Bldg - Food Retail	0 ft2	2,702 ft2	7,139 ft2	8,159 ft2	8,159 ft2	26,160 ft2
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail	0 ft2	15,116 ft2	39,707 ft2	45,379 ft2	45,379 ft2	145,581 ft2
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel	0 ft2	14,437 ft2	33,687 ft2	38,499 ft2	38,499 ft2	125,122 ft2
ECM86	Typical Lighting Project in Existing Bldg - Restaurant	0 ft2	3,982 ft2	9,291 ft2	10,618 ft2	10,618 ft2	34,510 ft2
ECM87	Typical Lighting Project in Existing Bldg - Recreation	0 ft2	0 ft2	0 ft2	0 ft2	0 ft2	0 ft2
ECM88	Typical Lighting Project in Existing Bldg - Warehouse	0 ft2	11,460 ft2	26,739 ft2	30,559 ft2	30,559 ft2	99,316 ft2

Exhibit 2: Participation Projections – Prescriptive LED Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM92	Commercial 12W LED A19 Bulb	0 units	555 units	1,295 units	1,480 units	1,480 units	4,810 units
ECM93	Commercial 8W LED A19 Bulb	0 units	1,184 units	2,763 units	3,157 units	3,157 units	10,261 units
ECM94	Commercial LED MR16 Bulbs	0 units	925 units	2,158 units	2,467 units	2,467 units	8,016 units
ECM95	Commercial LED PAR30 Bulbs	0 units	740 units	1,727 units	1,973 units	1,973 units	6,413 units
ECM96	Commercial LED PAR38 Bulbs	0 units	538 units	1,256 units	1,435 units	1,435 units	4,664 units
ECM97	Commercial Spot or task lighting	0 units	370 units	863 units	987 units	987 units	3,206 units

Exhibit 3: Participation Projections – Lighting Redesign and Custom Lighting Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM912	Gov. Lighting Redesign Study	11,394 ft2	59,232 ft2	95,676 ft2	95,676 ft2	47,838 ft2	309,815 ft2
ECM802	Gov. Typical Lighting Project in	0 ft2	11,738 ft2	31,786 ft2	36,327 ft2	36,327 ft2	116,179 ft2
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health	0 ft2	4,421 ft2	10,316 ft2	11,789 ft2	11,789 ft2	38,315 ft2
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education	0 ft2	32,136 ft2	74,984 ft2	85,696 ft2	85,696 ft2	278,512 ft2
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation	0 ft2	5,798 ft2	13,528 ft2	15,461 ft2	15,461 ft2	50,247 ft2
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse	0 ft2	3,820 ft2	8,913 ft2	10,186 ft2	10,186 ft2	33,105 ft2

Exhibit 4: Participation Projections – Prescriptive LED Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM922	Gov. Commercial 12W LED A19 Bulb	0 units	299 units	697 units	797 units	797 units	2,590 units
ECM932	Gov. Commercial 8W LED A19 Bulb	0 units	638 units	1,488 units	1,700 units	1,700 units	5,525 units
ECM942	Gov. Commercial LED MR16 Bulbs	0 units	498 units	1,162 units	1,328 units	1,328 units	4,316 units
ECM952	Gov. Commercial LED PAR30 Bulbs	0 units	398 units	930 units	1,063 units	1,063 units	3,453 units
ECM962	Gov. Commercial LED PAR38 Bulbs	0 units	290 units	676 units	773 units	773 units	2,511 units
ECM972	Gov. Commercial Spot or task lighting	0 units	199 units	465 units	531 units	531 units	1,727 units

High Efficiency Refrigeration Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 42)*

Exhibit 5: Participation Projections – High Efficiency Refrigeration Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM98	Typical Low-Cost No-Cost Refrigeration Project - Food	0 ft2	0 ft2	30,582 ft2	0 ft2	30,582 ft2	61,163 ft2
ECM99	Typical Deep Retrofit	0 ft2	0 ft2	30,252 ft2	0 ft2	30,252 ft2	60,505 ft2

Exhibit 6: Participation Projections – High Efficiency Refrigeration Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM1002	Typical Refrigeration Project - Ice Rink	0 ft2	0 ft2	24,760 ft2	0 ft2	24,760 ft2	49,520 ft2

Energy Star Computer Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 42)*

Exhibit 43: Participation Projections – ENERGY STAR Computer Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM101	ES Desktop Computer and Monitor	45 units	283 units	461 units	0 units	0 units	788 units
ECM102	ES Laptop Computer	30 units	188 units	307 units	0 units	0 units	525 units

Exhibit 44: Participation Projections – ENERGY STAR Computer Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM1012	Gov. ES Desktop Computer and Monitor	178 units	1,130 units	1,844 units	0 units	0 units	3,153 units
ECM1022	Gov. ES Laptop Computer	119 units	754 units	1,229 units	0 units	0 units	2,102 units

New Construction Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 57)*

Exhibit 7: Participation Projections – Electricity-Efficient New Construction Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM89	Typical High-Performance New Building - 25% Better	0 ft2	1,992 ft2	8,966 ft2	13,947 ft2	15,939 ft2	40,844 ft2
ECM90	Typical High-Performance New	0 ft2	311 ft2	1,401 ft2	2,179 ft2	2,490 ft2	6,382 ft2

Exhibit 8: Participation Projections – Electricity-Efficient New Construction Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM892	Gov. Typical High-Performance New Building - 25% Better	0 ft2	1,073 ft2	4,828 ft2	7,510 ft2	8,583 ft2	21,993 ft2
ECM902	Gov. Typical High-Performance	0 ft2	168 ft2	754 ft2	1,173 ft2	1,341 ft2	3,436 ft2

Residential Programs

LED Lighting and Automotive Block-Heater Timers - *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 76)*

Exhibit 9: Participation Projections – LED Lighting and Block-Heater Timer Rebates

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM151	Block Heater Timer	0 units	68 units	109 units	109 units	109 units	395 units
ECM24	12W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM60	8W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM61	LED MR16 Bulbs	55 units	259 units	259 units	259 units	259 units	1,089 units
ECM62	LED PAR30 Bulbs	14 units	79 units	79 units	79 units	79 units	328 units
ECM63	LED PAR38 Bulbs	10 units	59 units	59 units	59 units	59 units	246 units
ECM44	Spot or Task Lighting	9 units	41 units	41 units	41 units	41 units	172 units

Low Cost Energy Efficiency Products - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 86)*

Exhibit 10: Participation Projections –Low-cost Energy Efficient Products

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM242	Pilot 12W LED A19 Bulb	60 units	60 units	60 units	60 units	60 units	300 units
ECM602	Pilot 8W LED A19 Bulb	60 units	60 units	60 units	60 units	60 units	300 units
ECM612	Pilot LED MR16 Bulbs	40 units	40 units	40 units	40 units	40 units	200 units
ECM622	Pilot LED PAR30 Bulbs	30 units	30 units	30 units	30 units	30 units	150 units
ECM632	Pilot LED PAR38 Bulbs	20 units	20 units	20 units	20 units	20 units	100 units
ECM442	Pilot Spot or Task Lighting	6 units	6 units	6 units	6 units	6 units	30 units
ECM092	Pilot Ultra Low-flow Showerheads	30 units	40 units	30 units	20 units	20 units	140 units
ECM112	Pilot Smart, Surge Protected Power Bars for PCs and TVs	60 units	60 units	40 units	40 units	30 units	230 units
ECM182	Pilot DHW Tank Insulation	40 units	60 units	60 units	40 units	40 units	240 units
ECM202	Pilot DHW Pipe Insulation	40 units	60 units	60 units	40 units	40 units	240 units
ECM482	Pilot Motion Detectors - Indoor and Outdoor	60 units	60 units	40 units	40 units	30 units	230 units
ECM152	Pilot Auto Heater Timers	30 units	60 units	60 units	60 units	60 units	270 units
ECM142	Pilot Prog. Thermostats (Central)	10 units	20 units	15 units	10 units	10 units	65 units
ECM212	Pilot Prog. Thermostats	50 units	90 units	80 units	60 units	40 units	320 units
ECM062	Pilot E-Star TVs	2 units	2 units	2 units	2 units	2 units	10 units
ECM082	Pilot ESTAR Printers and Fax	4 units	4 units	4 units	4 units	4 units	20 units
ECM091	Ed. Ultra Low-flow Showerheads	45 units	92 units	102 units	112 units	112 units	464 units
ECM111	Ed. Smart, Surge Protected Power Bars for PCs and TVs	117 units	505 units	525 units	525 units	535 units	2,207 units

CCHP and GSHP Initiative - *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 94)*

Exhibit 11: Participation Projections – CCHP and GSHP Initiatives

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM032	Pilot Cold Temp Heat Pumps	1 units	0 units	0 units	1 units	0 units	2 units
ECM372	Pilot Ground Heat Pumps - Closed	0 units	1 units	1 units	0 units	0 units	2 units
ECM03	Cold Temp Heat Pumps	0 units	0 units	0 units	6 units	6 units	12 units
ECM37	Ground Heat Pumps - Closed	0 units	0 units	0 units	1 units	1 units	2 units

WL-YECL-2

Reference: Section 1, Schedules 8.8 and 8.9

On page 1-4, YECL states that the 3-year amortization cost of the Phase 1 GRA is $139,000 and that choosing a 3-year test period produces annual savings of $69,500 compared to a 2-year test period.

Request:

(a) Please indicate where in the schedules provided with the GRA the 3-year annual amortization cost of $139,000 is shown. If it is not shown in any schedule provided then please provide such a schedule that also shows the proposed annual amortization costs of the Phase 2 GRA.

(b) There was a 3-year gap (2010-2012) between GRA test years (2009 – 2013). Assuming the 1st test year of the next Phase 1 GRA is not until 2017, 2018 or 2019, please estimate the savings if the 2013-2015 Phase 1 and Phase 2 GRA costs are amortized over periods that end in 1) 2016, 2) 2017 and 3) 2018.

Response:

(a) The proposed three year amortization of the forecast Phase I and Phase 2 costs are reflected in the calculations on Schedule 8.8 of Yukon Electrical's Application.

Forecast Phase 1 costs = $417,000 / 3 years = $139,000/year
Forecast Phase 2 costs = $193,000 / 3 years = $64,333/year

The above noted amortizations result in the Rate Case Deferral Account reaching a zero balance at the end of the 2015 test period.

(b) The forecast savings of amortizing the costs over 4, 5 and 6 year period (2016, 2017 and 2018), respectively, are:

4 years (2016) = ($417,000+$193,000) / 4 years = $152,500/year
($139,000+$64,333) - $152,500 = $50,833 savings/year

5 years (2017) = ($417,000+$193,000) / 5 years = $122,000/year
($139,000+$64,333) - $122,000 = $81,333 savings/year

6 years (2018) = ($417,000+$193,000) / 6 years = $101,667/year
($139,000+$64,333) - $101,667 = $101,666 savings/year

WL-YECL-6

Reference: Treatment Under IFRS vs Regulatory, Section 1 Attachment 2

The Table in Attachment 3 provides a comparison of the treatment of significant items for Financial Statement purposes and regulatory purposes, post IFRS. Watson Lake wishes to understand the reasons for any differences in IFRS treatment of significant items by YECL and ATCO Electric Ltd.

Request:

(a) Please indicate whether the treatment of the significant items under IFRS for Financial Statement purposes, as set out in the Table in Attachment 2 is consistent with treatment of the same items for financial statement purposes by YECL's parent, ATCO Electric Ltd or its affiliates Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd. If there are differences please identify the differences and the reasons for them.

(b) Please indicate whether the treatment of the significant items for regulatory purposes as set out in the Table in Attachment 2 is consistent with treatment of the same items for regulatory purposes by NUL's parent, ATCO Electric Ltd. and its affiliates NUL(YK) and NUL(NWT). If there are differences please identify the differences and the reasons.

(c) Please indicate how revenues that are interim as of fiscal year-end are treated for Financial Statement purposes under IFRS. Indicate whether there has been any change in the Financial Statement treatment of revenues that remain unapproved as of fiscal year end, due to regulatory lag, as a result of the transition from GAAP to IFRS. Please elaborate.

Response:

(a) Yukon Electrical's treatment of significant items under IFRS for Financial Statement purposes, as set out in the Table in Attachment 2 of its Application, is consistent with the treatment of the same items by Yukon Electrical's parent, ATCO Electric Ltd., and its affiliates, Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd.

(b) Yukon Electrical's treatment of significant items for regulatory purposes, as set out in the Table in Attachment 2 of its Application, is consistent with the treatment of the same items by Yukon Electrical's parent, ATCO Electric Ltd., and its affiliates, Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd.

(c) A summary of the recording of revenues under IFRS and historical Canadian GAAP ("historical GAAP") is as follows:

- Under IFRS as well as historical GAAP, interim revenues are (were) recorded as revenues when billed to customers.

- For revenues that remain unapproved as of current fiscal year end, revenues could not be recorded under historical GAAP nor can they be recorded under IFRS.

- For revenues that are approved as of fiscal year end but are to be collected prospectively in the next fiscal year, historical GAAP allowed them to be recorded as a regulatory receivable at year end. In the case of IFRS, regulatory assets, such as revenue receivables, are written-off at year end. Revenues can only be recorded as revenues when they are billed to customers.

WL-YECL-8

Reference: Sales and Revenues, Section 2

The Board would like further support with respect to the customer forecasts and regression analysis

Request:

(a) Please expand Table 1 to include 2008, 2009 and 2010 and also to show the sales variances in each year subsequent to 2008 (so 2009 to 2015) caused by 1) the change in number of customers, 2) the change in consumption per customer (normalized for residential) and 3) the impact of the demand side management program. For 2013 to 2015 this analysis should be presented relative to the corresponding GRA forecasts.

(b) Please explain the decreasing Private Lights sales in Table 1.

(c) YECL partially attributes its increasing residential sales to increased use of electricity for space heating. Please explain the reasons for the increased interest in the use of electricity for space heating in Whitehorse. Has the interest in electricity for space heating increased in other communities? Why or why not?

(d) Please provide an analysis of the elasticity of demand for electricity for space heating relative to a range of prices of electricity (with that range including the expected $/kwh arising from this Phase 1 and the upcoming Phase 2 for the test years). This analysis should take into consideration the forecast costs for competing options for heating energy.

(e) Should cooling degree days (CDD) be a factor in forecasting electricity usage to take into account use of electricity for space cooling?

(f) Please expand Schedule 2.1 so that it presents customers, sales and revenue by community.

(g) Please explain why Section 2 Attachment 20 only shows the 20-year “Normal” HDD for Whitehorse and Watson Lake.

(h) Please provide a schedule showing the calculation of the UPC for each community (residential and commercial) from 2008 to 2015 with all calculations clearly shown and with references to Attachments 1 to 21 of Section 2.

(i) Please discuss the meaning of differences (higher vs. lower and magnitude), and the reasons for these differences, in the coefficients of HDD for the different communities.

(j) Please indicate whether there are any observable trends with respect to residential consumption per customer in each community (for example due to conservation, size of housing units, etc). Indicate whether the introduction of a trend factor into the regression analysis would help improve the R^2 values in the regression analysis. Provide all supporting analysis with respect to this response.

(k) Please indicate why 18 degrees Celsius was chosen as the balance point for temperature normalization. Please provide an analysis showing the sensitivity of the regression results to lower temperatures being used as the balance point.

(l) Given the relatively small size of some communities please indicate whether it would make sense to group the customers under single family residences and multifamily units for the purposes of the regression analysis. Does YECL have the necessary data for such analysis?

(m) Please indicate whether any 2013 published housing starts forecasts data were considered in the development of the residential sales forecast. If so, please provide the sources and the data used and show how this information was factored into the forecasts. If 2013 housing starts data was not used, please explain why not.

(n) Please provide a schedule showing the calculation of the commercial sales per community starting from the number of customers and the UPC.

(o) Please explain why temperature normalized sales were not used to arrive at the average consumption per customer for commercial customers. Please provide an analysis that would show the calculation of the commercial consumption per customer for each test year using temperature normalized sales per customer. Indicate whether the stratification of the commercial customers by size would help produce better R^2 values.

(p) Please explain the large increases in reconnect revenue starting in 2012 shown in Schedule 2.2.

Response:

(a) Please refer to WL-YECL-8(a) Attachment 1.

(b) Yukon Electrical has observed a declining trend in the actual number of private lighting customers since 2008 and therefore a declining trend in sales. Yukon Electrical does not invest in private lighting, thus the customer is responsible for 100% of the capital cost to install a new light. As a result, Yukon Electrical believes that customers are choosing alternate sources of lighting. Yukon Electrical has assumed that this trend will continue into the forecast years.

(c) Yukon Electrical has observed an increased interest in use of electricity for space heating in Whitehorse in recent years. Although Yukon Electrical is not involved with consumer's choices of heating sources for their homes, Yukon Electrical presumes that this could be related to the construction costs of installing central heating systems supplied by propane, home heating fuel or wood, versus the installation of an electric baseboard heating system. The use of electricity for space heating is not permitted in the isolated diesel communities without written permission from Yukon Electrical.

(d) Yukon Electrical has not performed an analysis of the elasticity of demand for electricity for space heating for Yukon due to the complexity of the study, lack of appropriate data and extensive amount of time it would take to perform such a study. However, based on a survey of studies reported for some jurisdictions in the U.S. by the Electric Power Research Institute titled, "Price Elasticity of Demand for Electricity: A Primer and Synthesis", dated January 2008, the elasticity of demand for general electricity use (not specifically for space heating) is estimated in the range of -0.2% to -0.6% in the short-run (1-5 years), and -0.7% to -1.4% in the long-run for residential customers, and between -0.2% to -0.7% in the short-run, and -0.8% to -1.3% in the long-run for commercial customers. Based on these numbers, for example, a 10% increase in the price of electricity of the residential rate class in the short-run would result in, everything else being constant, a 2% to 6% drop in electricity consumption by

residential customers. For commercial customers, the same increase in price in the short-run would result in, everything else being constant, a 2% to 7% drop in electricity consumption. It should be noted that these elasticity estimates were all derived for jurisdictions with enabling technologies that provide for some sort of time-variable pricing (dynamic pricing) such as Time of Use, Critical Peak Pricing, or Real Time Pricing. As such, these customers are more aware and capable to react to price changes, if they choose to do so. While Yukon Electrical's sales forecast does not incorporate reduced consumption caused from increased prices, there is a risk that actual sales will be lower than forecast.

(e) No, because CDD data is not consistently available for the 20 years that Yukon Electrical has used for the HDD variable as an input into the weather-normalization process. Also, Yukon Electrical's service area is in a cooler climate where there are very few CDD days within a year.

(f) Please refer to WL-YECL-8(f) Attachment 1 for the expanded Schedule 2.1 by Rate Zone (Hydro, Large diesel, Small Diesel and Old Crow). As the revenue forecast is calculated on a Rate Zone basis, Yukon Electrical does not have the forecast available on a community basis.

(g) Environment Canada does not provide historical HDD data, consistent with that of Whitehorse and Watson Lake, for other communities within Yukon Electrical's service area.

(h) The calculation of residential UPC by community from 2008 to 2015 is provided in WL-YECL-8(h) Attachments 1 to 21. Please refer to CW-YECL-3 for details of the commercial UPC forecast.

(i) The coefficient of HDD in each community indicates the impact of one unit change in HDD on the average electricity consumption (UPC) for a typical customer in that community. For example, in the case of Whitehorse, a one unit change in HDD leads to an estimated 0.54 kWh change in the average electricity consumption of a typical Whitehorse residential customer (Attachment 21, Page 1 of 7, of the Application). The higher the coefficient, with everything else being equal, the higher the impact of HDD would be on the average electricity consumption. In reality, however, many factors contribute to the variations in HDD coefficients among different communities. For example, different patterns and uses of electricity among different communities, such as:

- different level of penetration of electric devices among households;
- the size/mixture of the households (eg. share of young people versus older people);
- income level;
- the structure/type/size of dwelling (wood/concrete);
- single detached versus multi-family dwelling; and
- small versus large house.

(j) While the conservation efforts, size and mixture of housing units will influence the average electricity consumption in a community, it would be difficult to attribute the long-term trend in the average consumption in Yukon communities to any one factor without a careful examination and detailed study. Such a study would require detailed historical data, which is unavailable in the Yukon Territory. Yukon Electrical has not undertaken such a study, and therefore is unable to provide any comment. It should also be noted that Yukon Electrical's use of regression analysis was solely for the purpose of identifying and quantifying the impact of weather on the average consumption so that the three-year averaging method, which was utilized in forecasting the UPC, would be free from the impact of an abnormally cold/warm year. Adding a trend variable to the regression equation would depart from that purpose, and obscure the impact of the weather variable.

(k) Yukon Electrical uses 18 degrees Celsius as the balance point for temperature-normalization as it is based on the definition Environment Canada uses and provides data for heating degree days (HDD). Heating Degree Days is defined by Environment Canada as:

> "Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. If the temperature is equal to or greater than 18°C, then the number will be zero."

Yukon Electrical has always used the official data from Environment Canada and has not considered using a different balancing point other than the one officially

produced. As a result, Yukon Electrical is unable to provide an analysis showing the sensitivity of regression results to lower temperatures being used as the balance point.

(l) Yukon Electrical does not believe separately grouping customers by single family and multi-family housing would make sense, all customers in the residential rate class in a particular rate zone are charged the same rate regardless of the type of residence. In addition, Yukon Electrical does not have the necessary data available to undertake such an analysis.

(m) 2013 housing starts data was not used because at the time the forecast was being prepared there was no published report available.

(n) Please refer to CW-YECL-3.

(o) Please refer to YEC-YECL-4(c) for an explanation on how the commercial UPC was derived.

The stratification of data by size may not help produce better R^2 values if the customers in the strata are different in their use of electricity and if there business activities are not temperature-sensitive. The stratification may also introduce problems associated with a small sample size bias.

(p) The reconnect fee schedule changed in July 2011. This was part of the T&C's Schedule "D" update: The normal fee to set up an account changed from $15 to $50. Also a collection fee for visits to a delinquent customer changed from $0 to $30. Reconnect after disconnection for non-payment changed from $50 to $60.

Table 1

Yukon Electrical Sales by Customer Class[1]

	Actual									Test Period					
	2008	2009	Energy (MWh) (2009-2008)	2010	Energy (MWh) (2010-2009)	2011	Energy (MWh) (2011-2010)	2012	Energy (MWh) (2012-2011)	2013	Energy (MWh) (2012-2011)	2014	Energy (MWh) (2012-2011)	2015	Energy (MWh) (2012-2011)
Residential															
Sales (MWh)[2]	125,407	130,563	5,156	133,622	3,059	141,204	7,582	147,845	6,641	151,793	3,948	154,381	2,588	157,023	2,642
Customer	12,715	12,943	2,250	13,170	2,295	13,482	3,158	13,857	3,936	14,159	3,217	14,401	2,592	14,647	2,643
UPC(kWh)[2]	9,863	10,088	2,905	10,146	764	10,474	4,424	10,669	2,706	10,721	731	10,720	(4)	10,720	(1)
DSM Impact (MWh)[3]												88	88	402	314
Commercial															
Sales (MWh)	141,704	142,076	372	145,776	3,700	150,591	4,815	159,562	8,971	161,564	2,003	165,095	3,531	168,549	3,453
Customer	2,600	2,630	1,630	2,692	3,349	2,774	4,454	2,841	3,632	2,867	1,446	2,903	2,033	2,948	2,554
UPC (kWh)	54,496	54,018	(1,259)	54,148	351	54,278	362	56,157	5,338	56,351	557	56,867	1,497	57,172	899
DSM Impact (MWh)[3]												11	11	305	294
Street Lights															
Sales (MWh)	3,545	3,477	(68)	3,647	170	3,598	(49)	3,771	173	3,725	(47)	3,789	64	3,854	64
Private Lights															
Sales (MWh)	631	592	(39)	594	2	581	(13)	560	(20)	554	(6)	544	(10)	534	(10)
Sub-Total	**271,287**	**276,708**	**5,421**	**283,639**	**6,931**	**295,974**	**12,335**	**311,739**	**15,765**	**317,636**	**5,897**	**323,809**	**6,173**	**329,959**	**6,150**
Industrial						-		-		1,025	-	4,620	-	4,620	-
Total	**271,287**	**276,708**	**5,421**	**283,639**	**6,931**	**295,974**	**12,335**	**311,739**	**15,765**	**318,661**	**6,922**	**328,429**	**9,768**	**334,579**	**6,150**

1) With the exception of data for Residential and the DSM impact, data in this table are from Schedule 2.1.

2) Sales and UPC data are on a weather-normalized basis

3) DSM initiative is assumed to be approved and is incorporated in the sales numbers in 2014 and 2015.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Total

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Existing 2013	Test Period Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	12,715	12,943	13,169	13,482	13,857	14,159	14,401	14,647
3	Sales in MWh	128,302	130,569	131,273	141,696	150,350	151,793	154,381	157,023
4	MWh sales per customer	10.1	10.1	10.0	10.5	10.8	10.7	10.7	10.7
5	Revenue ($000s)	16,671	16,307	16,892	18,928	21,127	21,294	21,657	22,028
6	Cents per KWh	12.99	12.49	12.87	13.36	14.05	14.03	14.03	14.03
7	**Commercial**								
8	Customers (average during year)	2,600	2,630	2,692	2,774	2,841	2,867	2,903	2,948
9	Sales in MWh	141,704	142,077	145,776	150,591	159,562	161,564	165,095	168,549
10	MWh sales per customer	54.5	54.0	54.1	54.3	56.2	56.4	56.9	57.2
11	Revenue ($000s)	20,818	20,368	21,621	23,374	26,057	26,398	27,015	27,602
12	Cents per KWh	14.69	14.34	14.83	15.52	16.33	16.34	16.36	16.38
13	**Industrial**								
14	Customers (average during year)	0	0	0	0	0	1	1	1
15	Sales in MWh	0	0	0	0	0	1,025	4,620	4,620
16	MWh sales per customer						1,025	4,620	4,620
17	Revenue ($000s)	0	0	0	0	0	143	612	612
18	Cents per KWh						13.91	13.26	13.26
19	**Street lights**								
20	Sales in MWh	3,545	3,477	3,647	3,598	3,771	3,725	3,789	3,854
21	Revenue ($000s)	776	764	848	881	963	951	966	981
22	Cents per KWh	21.89	21.98	23.24	24.47	25.53	25.54	25.49	25.45
23	**Private lights**								
24	Sales in MWh	631	592	594	581	560	554	544	534
25	Revenue ($000s)	139	131	138	144	147	145	143	141
26	Cents per KWh	22.04	22.18	23.29	24.72	26.20	26.23	26.27	26.31
27	**Total Company - Retail - Primary**								
28	Customers	15,315	15,573	15,862	16,256	16,699	17,026	17,304	17,595
29	Sales in MWh	274,182	276,714	281,290	296,466	314,244	318,661	328,429	334,579
30	Revenue ($000s)	38,404	37,570	39,500	43,326	48,293	48,931	50,393	51,363
31	Cents/KWh	14.01	13.58	14.04	14.61	15.37	15.36	15.34	15.35
32	**Secondary Sales**								
33	Customers (average during year)	22	21	21	14	2	0	0	0
34	Sales in MWh	18,053	16,843	10,153	552	1,993	0	0	0
35	MWh sales per customer	821	802	483	39	997	-	-	-
36	Revenue ($000s)	1,389	1,092	665	41	164	0	0	0
37	Cents per KWh	7.69	6.48	6.55	7.43	8.23	-	-	-
38	**Wholesale Sales**								
39	Customers (average during year)	2	2	2	2	2	2	2	2
40	Sales in MWh	412	360	365	427	338	338	338	338
41	MWh sales per customer	206	180	183	214	169	169	169	169
42	Revenue ($000s)	41	37	38	38	28	28	28	28
43	Cents per KWh	9.95	10.28	10.41	8.90	8.30	8.30	8.30	8.30
44	**Total Company**								
45	Customers	15,339	15,596	15,885	16,272	16,703	17,028	17,306	17,597
46	Sales in MWh	292,647	293,917	291,808	297,445	316,575	318,999	328,768	334,917
47	Revenue ($000s)	39,834	38,699	40,202	43,405	48,486	48,959	50,421	51,391
48	Cents/KWh	13.61	13.17	13.78	14.59	15.32	15.35	15.34	15.34
49	Total Revenues	39,834	38,699	40,202	43,405	48,486	48,959	50,421	51,391

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Hydro Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	11,701	11,921	12,146	12,456	12,834	13,143	13,368	13,596
3	Sales in MWh	119,640	121,938	122,732	132,820	141,284	143,018	145,460	147,947
4	MWh sales per customer	10.2	10.2	10.1	10.7	11.0	10.9	10.9	10.9
5	Revenue ($000s)	15,495	15,171	15,722	17,670	19,792	20,005	20,346	20,694
6	Cents per KWh	12.95	12.44	12.81	13.30	14.01	13.99	13.99	13.99
7	**Commercial**								
8	Customers (average during year)	2,253	2,288	2,346	2,415	2,483	2,525	2,557	2,597
9	Sales in MWh	132,077	132,624	136,223	141,006	149,182	151,698	154,915	158,215
10	MWh sales per customer	58.6	58.0	58.1	58.4	60.1	60.1	60.6	60.9
11	Revenue ($000s)	19,187	18,838	20,030	21,749	24,283	24,729	25,284	25,845
12	Cents per KWh	14.53	14.20	14.70	15.42	16.28	16.30	16.32	16.34
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	1	1	1
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	1,025	4,620	4,620
16	MWh sales per customer						1,025	4,620	4,620
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	143	612	612
18	Cents per KWh						13.91	13.26	13.26
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	13,954	14,209	14,492	14,871	15,318	15,668	15,925	16,193
21	Sales in MWh	251,717	254,561	258,955	273,827	290,466	295,741	304,995	310,781
22	Revenue ($000s)	34,683	34,009	35,752	39,418	44,076	44,876	46,242	47,152
23	Cents/KWh	13.78	13.36	13.81	14.40	15.17	15.17	15.16	15.17
24	**Secondary Sales**								
25	Customers (average during year)	22	21	21	14	2	-	-	-
26	Sales in MWh	18,053	16,843	10,153	552	1,993	-	-	-
27	MWh sales per customer	820.6	802	483	39	997	-	-	-
28	Revenue ($000s)	1,389	1,092	665	41	164.1	-	-	-
29	Cents per KWh	7.69	6.48	6.55	7.43	8.23	-	-	-
30	**Wholesale Sales**								
31	Customers (average during year)	2	2	2	2	2	2	2	2
32	Sales in MWh	412	360	365	427	338	338	338	338
33	MWh sales per customer	206	180	183	214	169	169	169	169
34	Revenue ($000s)	41	37	38	38	28	28	28	28
35	Cents per KWh	9.95	10.28	10.41	8.90	8.30	8.30	8.30	8.30
36	**Total Company (Excluding Lights)**								
37	Customers	13,978	14,232	14,515	14,887	15,322	15,670	15,927	16,195
38	Sales in MWh	270,182	271,764	269,473	274,806	292,797	296,079	305,333	311,120
39	Revenue ($000s)	36,113	35,138	36,455	39,497	44,268	44,904	46,271	47,180
40	Cents/KWh	13.37	12.93	13.53	14.37	15.12	15.17	15.15	15.16
41	Total Revenues	36,113	35,138	36,455	39,497	44,268	44,904	46,271	47,180

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Large Diesel Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	710	716	719	719	712	703	715	727
3	Sales in MWh	6,493	6,445	6,352	6,496	6,617	6,345	6,454	6,567
4	MWh sales per customer	9.1	9.0	8.8	9.0	9.3	9.0	9.0	9.0
5	Revenue ($000s)	847	814	838	886	952	914	929	946
6	Cents per KWh	13.05	12.64	13.19	13.63	14.38	14.40	14.40	14.40
7	**Commercial**								
8	Customers (average during year)	201	199	201	208	209	202	204	207
9	Sales in MWh	6,597	6,562	6,681	6,537	7,287	7,030	7,300	7,408
10	MWh sales per customer	32.8	32.9	33.3	31.4	34.8	34.9	35.8	35.8
11	Revenue ($000s)	1,023	962	1,010	1,055	1,227	1,173	1,228	1,246
12	Cents per KWh	15.51	14.66	15.12	16.14	16.83	16.69	16.82	16.81
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	911	915	920	927	922	904	918	934
21	Sales in MWh	13,090	13,006	13,033	13,033	13,904	13,376	13,754	13,974
22	Revenue ($000s)	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191
23	Cents/KWh	14.29	13.66	14.18	14.89	15.67	15.60	15.68	15.68
24	**Total Company (Excluding Lights)**								
25	Customers	911	915	920	927	922	904	918	934
26	Sales in MWh	13,090	13,006	13,033	13,033	13,904	13,376	13,754	13,974
27	Revenue ($000s)	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191
28	Cents/KWh	14.29	13.66	14.18	14.89	15.67	15.60	15.68	15.68
29	Total Revenues	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Small Diesel Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	167	166	165	168	169	170	172	176
3	Sales in MWh	1,242	1,212	1,210	1,290	1,373	1,337	1,360	1,383
4	MWh sales per customer	7.4	7.3	7.4	7.7	8.1	7.9	7.9	7.9
5	Revenue ($000s)	184	172	178	193	211	204	207	211
6	Cents per KWh	14.78	14.20	14.71	14.99	15.38	15.25	15.24	15.25
7	**Commercial**								
8	Customers (average during year)	109	107	109	111	108	99	100	102
9	Sales in MWh	2,266	2,119	2,135	2,222	2,191	1,956	1,987	2,020
10	MWh sales per customer	20.8	19.8	19.6	20.1	20.2	19.8	19.8	19.8
11	Revenue ($000s)	401	369	385	389	384	345	351	357
12	Cents per KWh	17.68	17.39	18.02	17.51	17.55	17.66	17.66	17.66
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	276	273	273	279	278	269	273	278
21	Sales in MWh	3,507	3,331	3,345	3,513	3,563	3,293	3,346	3,403
22	Revenue ($000s)	584	541	563	582	596	549	558	568
23	Cents/KWh	16.65	16.23	16.82	16.58	16.72	16.68	16.68	16.68
24	**Total Company (Excluding Lights)**								
25	Customers	276	273	273	279	278	269	273	278
26	Sales in MWh	3,507	3,331	3,345	3,513	3,563	3,293	3,346	3,403
27	Revenue ($000s)	584	541	563	582	596	549	558	568
28	Cents/KWh	16.65	16.23	16.82	16.58	16.72	16.68	16.68	16.68
29	Total Revenues	584	541	563	582	596	549	558	568

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Old Crow Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	137	140	139	140	142	144	146	148
3	Sales in MWh	928	975	979	1,089	1,076	1,092	1,107	1,126
4	MWh sales per customer	6.7	6.9	7.0	7.8	7.6	7.6	7.6	7.6
5	Revenue ($000s)	145	149	155	179	171	172	174	177
6	Cents per KWh	15.65	15.33	15.80	16.46	15.93	15.72	15.72	15.72
7	**Commercial**								
8	Customers (average during year)	37	35	37	40	40	42	42	42
9	Sales in MWh	765	772	737	826	903	881	893	906
10	MWh sales per customer	20.8	21.8	20.0	20.6	22.3	21.0	21.3	21.6
11	Revenue ($000s)	207	199	196	181	163	150	152	155
12	Cents per KWh	27.08	25.76	26.62	21.95	18.02	17.06	17.06	17.06
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	174	176	176	180	182	186	188	190
21	Sales in MWh	1,692	1,747	1,716	1,915	1,978	1,973	2,000	2,032
22	Revenue ($000s)	352	348	351	360	334	322	326	332
23	Cents/KWh	20.82	19.94	20.45	18.83	16.88	16.32	16.32	16.31
24	**Total Company (Excluding Lights)**								
25	Customers	174	176	176	180	182	186	188	190
26	Sales in MWh	1,692	1,747	1,716	1,915	1,978	1,973	2,000	2,032
27	Revenue ($000s)	352	348	351	360	334	322	326	332
28	Cents/KWh	20.82	19.94	20.45	18.83	16.88	16.32	16.32	16.31
29	Total Revenues	352	348	351	360	334	322	326	332

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	
Jan-08	9,449	12,269,006	1,298		1,114	1,287		
Feb-08	9,442	11,196,255	1,186		955	1,121		
Mar-08	9,455	9,563,985	1,012		735	1,039		
Apr-08	9,457	8,909,635	942		517	929		
May-08	9,460	7,459,428	789		308	796		
Jun-08	9,482	6,603,909	696		226	662		
Jul-08	9,482	6,456,565	681		173	648		
Aug-08	9,497	6,657,098	701		188	689		
Sep-08	9,528	6,675,999	701		319	699		
Oct-08	9,584	7,021,661	733		563	721		
Nov-08	9,563	9,417,742	985		783	1,003		
Dec-08	9,605	9,714,521	1,011	10,734	1,186	895		
Jan-09	9,619	14,703,140	1,529		1,138	1,504		
Feb-09	9,659	10,841,086	1,122		955	1,057		
Mar-09	9,687	10,593,111	1,094		869	1,049		
Apr-09	9,672	9,145,387	946		515	934		
May-09	9,682	7,485,113	773		331	768		
Jun-09	9,688	6,821,759	704		144	713		
Jul-09	9,704	6,817,908	703		63	730		
Aug-09	9,701	6,086,861	627		158	632		
Sep-09	9,714	6,991,253	720		306	725		
Oct-09	9,752	7,526,949	772		542	771		
Nov-09	9,773	9,319,856	954		782	973		
Dec-09	9,800	9,929,465	1,013	10,956	943	1,027	10,883	
Jan-10	9,815	13,210,358	1,346		991	1,401		
Feb-10	9,830	9,953,362	1,013		679	1,096		
Mar-10	9,830	9,242,694	940		656	1,010		
Apr-10	9,856	9,312,994	945		461	962		
May-10	9,849	7,831,404	795		292	811		
Jun-10	9,872	7,099,873	719		172	713		
Jul-10	9,891	6,781,330	686		117	683		
Aug-10	9,917	6,224,498	628		146	638		
Sep-10	9,914	7,144,977	721		332	711		
Oct-10	9,991	8,210,934	822		520	833		
Nov-10	10,030	9,069,490	904		718	958		
Dec-10	10,079	10,654,621	1,057	10,575	1,163	953	10,770	
Jan-11	10,094	14,500,257	1,437		1,010	1,481		
Feb-11	10,111	11,420,279	1,129		906	1,091		
Mar-11	10,111	12,700,787	1,256		902	1,193		
Apr-11	10,121	9,667,317	955		511	945		
May-11	10,130	9,045,994	893		296	907		
Jun-11	10,144	7,545,550	744		161	744		
Jul-11	10,164	6,885,882	677		128	670		
Aug-11	10,185	6,599,184	648		218	620		
Sep-11	10,201	7,524,695	738		329	731		
Nov-11	10,259	8,532,929	832		513	847		
Nov-11	10,340	9,756,743	944		936	879		
Dec-11	10,354	11,771,653	1,137	11,389	775	1,242	11,349	
Jan-12	10,393	14,103,108	1,357		1,118	1,343		
Feb-12	10,418	12,194,394	1,171		708	1,239		
Mar-12	10,441	11,466,512	1,098		756	1,114		
Apr-12	10,454	9,727,127	930		451	953		
May-12	10,476	8,747,823	835		351	820		
Jun-12	10,464	8,059,446	770		200	749		
Jul-12	10,529	7,464,066	709		140	694		
Aug-12	10,558	7,152,176	677		158	682		
Sep-12	10,586	7,358,794	695		287	710		
Oct-12	10,619	8,523,254	803		631	754		
Nov-12	10,643	10,766,338	1,012		970	929		
Dec-12	10,715	13,530,468	1,263	11,320	1,197	1,141	11,128	0.7%
2013-F							11,211	
2014-F							11,211	
2015-F							11,211	

Yukon Electrical Company Limited
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Carmacks Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	205	270,973	1,322		1,114	1,308	
Feb-08	206	360,272	1,749		955	1,669	
Mar-08	205	233,748	1,140		735	1,174	
Apr-08	203	177,314	873		517	857	
May-08	201	166,776	830		308	839	
Jun-08	210	149,015	710		226	667	
Jul-08	214	111,763	522		173	482	
Aug-08	217	149,074	687		188	673	
Sep-08	214	161,163	753		319	751	
Oct-08	217	178,995	825		563	810	
Nov-08	217	252,048	1,162		783	1,184	
Dec-08	212	231,535	1,092	11,665	1,186	949	
Jan-09	212	332,633	1,569		1,138	1,539	
Feb-09	217	268,232	1,236		955	1,156	
Mar-09	215	239,361	1,113		869	1,058	
Apr-09	213	212,235	996		515	982	
May-09	215	131,596	612		331	606	
Jun-09	215	122,920	572		144	583	
Jul-09	214	142,635	667		63	700	
Aug-09	210	125,620	598		158	603	
Sep-09	211	173,478	822		306	828	
Oct-09	213	173,164	813		542	813	
Nov-09	215	216,604	1,007		782	1,031	
Dec-09	216	234,408	1,085	11,091	943	1,103	
Jan-10	215	348,960	1,623		991	1,690	
Feb-10	214	220,292	1,029		679	1,132	
Mar-10	210	217,282	1,035		656	1,120	
Apr-10	208	212,864	1,023		461	1,044	
May-10	205	164,059	800		292	820	
Jun-10	208	117,689	566		172	558	
Jul-10	208	149,087	717		117	714	
Aug-10	207	139,344	673		146	686	
Sep-10	198	146,065	738		332	726	
Oct-10	204	176,915	867		520	881	
Nov-10	206	198,627	964		718	1,030	
Dec-10	204	219,265	1,075	11,111	1,163	947	11,350
Jan-11	204	330,275	1,619		1,010	1,673	
Feb-11	205	269,535	1,315		906	1,268	
Mar-11	205	251,463	1,227		902	1,150	
Apr-11	203	185,553	914		511	902	
May-11	204	179,502	880		296	897	
Jun-11	206	123,143	598		161	598	
Jul-11	204	138,322	678		128	668	
Aug-11	203	140,788	694		218	659	
Sep-11	205	172,792	843		329	834	
Nov-11	204	170,508	836		513	854	
Nov-11	208	229,421	1,103		936	1,024	
Dec-11	202	214,597	1,062	11,768	775	1,191	11,718
Jan-12	210	357,637	1,703		1,118	1,686	
Feb-12	211	251,282	1,191		708	1,275	
Mar-12	210	304,478	1,450		756	1,469	
Apr-12	212	146,362	690		451	718	
May-12	214	172,110	804		351	785	
Jun-12	210	158,825	756		200	730	
Jul-12	210	118,436	564		140	546	
Aug-12	210	159,385	759		158	764	
Sep-12	209	137,669	659		287	677	
Oct-12	210	168,280	801		631	742	
Nov-12	209	288,888	1,382		970	1,281	
Dec-12	213	274,853	1,290	12,050	1,197	1,140	11,815
2013-F							11,628
2014-F							11,628
2015-F							11,628

Yukon Electrical Company Limited
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Carcross Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	232	191,192	824		1,114	817	
Feb-08	233	223,919	961		955	922	
Mar-08	233	169,312	727		735	743	
Apr-08	232	159,486	687		517	680	
May-08	234	143,833	615		308	619	
Jun-08	236	116,358	493		226	472	
Jul-08	234	106,910	457		173	437	
Aug-08	237	120,069	507		188	500	
Sep-08	238	107,891	453		319	452	
Oct-08	235	116,583	496		563	489	
Nov-08	234	145,852	623		783	634	
Dec-08	235	170,315	725	7,568	1,186	655	
Jan-09	235	213,697	909		1,138	895	
Feb-09	237	211,727	893		955	854	
Mar-09	238	196,424	825		869	798	
Apr-09	238	181,815	764		515	757	
May-09	242	168,472	696		331	693	
Jun-09	243	125,606	517		144	522	
Jul-09	241	119,894	497		63	514	
Aug-09	242	106,627	441		158	443	
Sep-09	243	115,139	474		306	477	
Oct-09	245	137,384	561		542	561	
Nov-09	245	151,216	617		782	629	
Dec-09	245	182,836	746	7,941	943	755	
Jan-10	246	233,984	951		991	984	
Feb-10	248	229,357	925		679	975	
Mar-10	247	182,926	741		656	782	
Apr-10	247	166,931	676		461	686	
May-10	250	162,417	650		292	659	
Jun-10	251	133,093	530		172	527	
Jul-10	252	121,283	481		117	480	
Aug-10	252	115,715	459		146	466	
Sep-10	253	114,880	454		332	449	
Oct-10	251	144,645	576		520	583	
Nov-10	247	156,257	633		718	665	
Dec-10	247	170,916	692	7,768	1,163	630	7,885
Jan-11	247	256,402	1,038		1,010	1,065	
Feb-11	247	215,796	874		906	851	
Mar-11	248	230,708	930		902	893	
Apr-11	247	196,629	796		511	790	
May-11	253	148,572	587		296	596	
Jun-11	253	141,763	560		161	560	
Jul-11	253	115,593	457		128	452	
Aug-11	254	111,408	439		218	422	
Sep-11	252	130,273	517		329	513	
Nov-11	254	135,012	532		513	541	
Nov-11	252	155,215	616		936	577	
Dec-11	248	208,108	839	8,185	775	902	8,161
Jan-12	248	211,267	852		1,118	844	
Feb-12	248	252,902	1,020		708	1,061	
Mar-12	246	175,078	712		756	721	
Apr-12	248	169,800	685		451	698	
May-12	253	157,473	622		351	613	
Jun-12	253	137,494	543		200	531	
Jul-12	258	125,004	485		140	476	
Aug-12	257	131,406	511		158	514	
Sep-12	257	133,576	520		287	529	
Oct-12	254	132,319	521		631	492	
Nov-12	254	178,927	704		970	655	
Dec-12	251	205,670	819	7,994	1,197	746	7,879
2013-F							7,975
2014-F							7,975
2015-F							7,975

Yukon Electrical Company Limited
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Haines Junction Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	350	319,505	913		1,114	906	
Feb-08	352	298,048	847		955	809	
Mar-08	351	296,071	844		735	859	
Apr-08	351	235,359	671		517	663	
May-08	352	198,445	564		308	568	
Jun-08	354	184,683	522		226	501	
Jul-08	355	214,252	604		173	585	
Aug-08	355	187,109	527		188	520	
Sep-08	357	209,500	587		319	586	
Oct-08	355	184,518	520		563	513	
Nov-08	354	236,787	669		783	680	
Dec-08	354	268,108	757	8,023	1,186	689	
Jan-09	353	360,678	1,022		1,138	1,007	
Feb-09	352	257,154	731		955	693	
Mar-09	354	279,480	789		869	763	
Apr-09	352	225,364	640		515	633	
May-09	355	242,603	683		331	681	
Jun-09	356	195,099	548		144	553	
Jul-09	357	191,008	535		63	551	
Aug-09	359	182,361	508		158	510	
Sep-09	360	191,567	532		306	535	
Oct-09	358	206,898	578		542	578	
Nov-09	354	261,275	738		782	749	
Dec-09	358	250,902	701	8,005	943	709	
Jan-10	358	344,355	962		991	994	
Feb-10	359	256,515	715		679	763	
Mar-10	357	254,521	713		656	754	
Apr-10	360	219,524	610		461	620	
May-10	362	222,984	616		292	625	
Jun-10	363	209,884	578		172	575	
Jul-10	365	189,107	518		117	517	
Aug-10	369	180,314	489		146	495	
Sep-10	374	205,556	550		332	544	
Oct-10	372	212,879	572		520	579	
Nov-10	379	258,172	681		718	712	
Dec-10	378	268,489	710	7,713	1,163	650	7,827
Jan-11	378	377,850	1,000		1,010	1,025	
Feb-11	378	284,896	754		906	731	
Mar-11	378	292,208	773		902	736	
Apr-11	377	248,458	659		511	653	
May-11	379	252,259	666		296	674	
Jun-11	380	205,592	541		161	541	
Jul-11	383	205,103	536		128	531	
Aug-11	384	179,161	467		218	450	
Sep-11	384	198,252	516		329	512	
Nov-11	377	226,437	601		513	609	
Nov-11	383	261,152	682		936	644	
Dec-11	381	280,279	736	7,928	775	797	7,905
Jan-12	380	352,775	928		1,118	920	
Feb-12	383	314,667	822		708	861	
Mar-12	383	279,649	730		756	739	
Apr-12	382	250,547	656		451	669	
May-12	382	209,418	548		351	539	
Jun-12	384	230,104	599		200	587	
Jul-12	389	209,114	538		140	529	
Aug-12	389	167,224	430		158	432	
Sep-12	382	214,105	560		287	569	
Oct-12	388	221,577	571		631	543	
Nov-12	389	260,807	670		970	623	
Dec-12	386	349,387	905	7,958	1,197	834	7,846
2013-F							7,859
2014-F							7,859
2015-F							7,859

Yukon Electrical Company Limited
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Teslin Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	245	216,414	883		1,114	877	
Feb-08	247	232,931	943		955	908	
Mar-08	247	133,656	541		735	556	
Apr-08	249	135,849	546		517	538	
May-08	248	139,678	563		308	567	
Jun-08	252	105,137	417		226	398	
Jul-08	252	107,041	425		173	407	
Aug-08	249	132,160	531		188	524	
Sep-08	255	121,672	477		319	476	
Oct-08	258	155,094	601		563	595	
Nov-08	250	141,390	566		783	576	
Dec-08	252	161,590	641	7,134	1,186	577	
Jan-09	248	256,107	1,033		1,138	1,019	
Feb-09	224	205,093	916		955	880	
Mar-09	251	126,666	505		869	480	
Apr-09	254	137,937	543		515	537	
May-09	261	157,391	603		331	600	
Jun-09	263	110,039	418		144	423	
Jul-09	261	133,886	513		63	528	
Aug-09	263	112,418	427		158	430	
Sep-09	261	114,865	440		306	443	
Oct-09	261	146,569	562		542	561	
Nov-09	260	148,117	570		782	580	
Dec-09	258	170,066	659	7,188	943	667	
Jan-10	259	230,825	891		991	921	
Feb-10	259	166,034	641		679	687	
Mar-10	259	157,520	608		656	646	
Apr-10	259	168,540	651		461	660	
May-10	262	128,723	491		292	500	
Jun-10	262	120,573	460		172	457	
Jul-10	264	140,333	532		117	530	
Aug-10	263	101,789	387		146	393	
Sep-10	260	136,821	526		332	521	
Oct-10	263	143,157	544		520	550	
Nov-10	259	160,001	618		718	647	
Dec-10	261	204,972	785	7,135	1,163	728	7,242
Jan-11	260	223,209	858		1,010	883	
Feb-11	261	170,699	654		906	633	
Mar-11	260	213,994	823		902	789	
Apr-11	262	145,282	555		511	549	
May-11	259	159,685	617		296	624	
Jun-11	261	119,076	456		161	456	
Jul-11	264	134,793	511		128	506	
Aug-11	266	115,533	434		218	419	
Sep-11	267	142,094	532		329	528	
Nov-11	266	141,620	532		513	541	
Nov-11	267	159,981	599		936	564	
Dec-11	270	192,094	711	7,283	775	769	7,261
Jan-12	269	257,188	956		1,118	949	
Feb-12	269	181,756	676		708	713	
Mar-12	270	197,921	733		756	742	
Apr-12	272	157,130	578		451	590	
May-12	273	139,405	511		351	502	
Jun-12	273	136,904	501		200	490	
Jul-12	274	116,270	424		140	416	
Aug-12	276	107,721	390		158	393	
Sep-12	276	139,131	504		287	512	
Oct-12	279	138,414	496		631	469	
Nov-12	277	206,220	744		970	699	
Dec-12	277	215,033	776	7,290	1,197	709	7,185
2013-F							7,229
2014-F							7,229
2015-F							7,229

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Ross River Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	164	138,428	844		1,114	835	
Feb-08	166	180,188	1,085		955	1,034	
Mar-08	162	112,138	692		735	714	
Apr-08	167	101,559	608		517	598	
May-08	167	108,911	652		308	658	
Jun-08	168	83,087	495		226	467	
Jul-08	166	84,046	506		173	481	
Aug-08	167	88,077	527		188	518	
Sep-08	165	94,219	571		319	570	
Oct-08	166	92,484	557		563	548	
Nov-08	163	131,936	809		783	824	
Dec-08	164	125,781	767	8,115	1,186	675	
Jan-09	161	203,764	1,266		1,138	1,246	
Feb-09	165	132,362	802		955	751	
Mar-09	166	133,723	806		869	770	
Apr-09	167	114,214	684		515	674	
May-09	167	113,208	678		331	674	
Jun-09	165	93,976	570		144	577	
Jul-09	165	98,285	596		63	617	
Aug-09	164	88,391	539		158	542	
Sep-09	163	70,475	432		306	436	
Oct-09	164	115,117	702		542	702	
Nov-09	163	101,087	620		782	635	
Dec-09	163	138,640	851	8,544	943	862	
Jan-10	163	172,030	1,055		991	1,099	
Feb-10	165	127,134	771		679	837	
Mar-10	166	109,653	661		656	716	
Apr-10	168	125,996	750		461	764	
May-10	170	93,843	552		292	565	
Jun-10	169	88,991	527		172	522	
Jul-10	170	95,885	564		117	562	
Aug-10	168	80,787	481		146	489	
Sep-10	168	101,528	604		332	597	
Oct-10	165	96,733	586		520	595	
Nov-10	169	111,109	657		718	700	
Dec-10	169	161,797	957	8,165	1,163	875	8,320
Jan-11	170	186,091	1,095		1,010	1,130	
Feb-11	169	161,456	955		906	925	
Mar-11	170	162,357	955		902	905	
Apr-11	170	150,596	886		511	878	
May-11	173	112,717	652		296	663	
Jun-11	173	93,659	541		161	541	
Jul-11	171	96,055	562		128	555	
Aug-11	171	85,304	499		218	477	
Sep-11	169	105,303	623		329	617	
Nov-11	166	99,082	597		513	609	
Nov-11	168	107,996	643		936	592	
Dec-11	169	163,134	965	8,973	775	1,048	8,941
Jan-12	170	185,667	1,092		1,118	1,081	
Feb-12	170	166,679	980		708	1,035	
Mar-12	169	164,487	973		756	986	
Apr-12	169	120,116	711		451	729	
May-12	171	100,221	586		351	574	
Jun-12	169	108,363	641		200	624	
Jul-12	171	86,096	503		140	492	
Aug-12	174	91,515	526		158	529	
Sep-12	175	88,707	507		287	519	
Oct-12	179	100,177	560		631	521	
Nov-12	179	161,940	905		970	840	
Dec-12	178	175,254	985	8,969	1,197	888	8,817
2013-F							8,693
2014-F							8,693
2015-F							8,693

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Pelly Crossing Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	143	163,373	1,142		1,114	1,133	
Feb-08	144	185,324	1,287		955	1,349	
Mar-08	143	137,039	958		735	1,119	
Apr-08	142	81,727	576		517	834	
May-08	142	115,067	810		308	1,163	
Jun-08	143	86,991	608		226	998	
Jul-08	142	62,541	440		173	853	
Aug-08	141	87,862	623		188	1,030	
Sep-08	146	82,902	568		319	916	
Oct-08	146	107,401	736		563	974	
Nov-08	143	115,441	807		783	947	
Dec-08	145	128,250	884	9,441	1,186	842	
Jan-09	145	195,702	1,350		1,138	1,329	
Feb-09	146	150,422	1,030		955	976	
Mar-09	144	144,810	1,006		869	968	
Apr-09	145	100,376	692		515	682	
May-09	147	105,215	716		331	712	
Jun-09	148	80,962	547		144	555	
Jul-09	144	87,258	606		63	629	
Aug-09	144	76,992	535		158	538	
Sep-09	140	86,693	619		306	623	
Oct-09	144	121,044	841		542	840	
Nov-09	146	126,109	864		782	880	
Dec-09	144	133,097	924	9,729	943	936	
Jan-10	144	140,084	973		991	1,018	
Feb-10	143	118,028	825		679	895	
Mar-10	144	111,916	777		656	835	
Apr-10	142	117,096	825		461	839	
May-10	144	98,003	681		292	694	
Jun-10	145	79,965	551		172	546	
Jul-10	143	107,477	752		117	750	
Aug-10	146	75,911	520		146	529	
Sep-10	135	93,466	692		332	685	
Oct-10	141	97,842	694		520	703	
Nov-10	145	112,197	774		718	818	
Dec-10	145	121,245	836	8,900	1,163	750	9,063
Jan-11	145	181,367	1,251		1,010	1,288	
Feb-11	143	132,146	924		906	892	
Mar-11	147	133,068	905		902	853	
Apr-11	146	110,951	760		511	752	
May-11	144	110,139	765		296	776	
Jun-11	140	76,274	545		161	545	
Jul-11	144	92,521	643		128	636	
Aug-11	146	86,654	594		218	570	
Sep-11	146	104,289	714		329	708	
Nov-11	146	98,979	678		513	690	
Nov-11	148	131,772	890		936	837	
Dec-11	144	135,715	942	9,611	775	1,030	9,577
Jan-12	147	193,513	1,316		1,118	1,305	
Feb-12	146	131,098	898		708	955	
Mar-12	148	160,054	1,081		756	1,094	
Apr-12	148	88,485	598		451	617	
May-12	147	103,229	702		351	689	
Jun-12	145	115,883	799		200	782	
Jul-12	148	65,728	444		140	432	
Aug-12	148	96,215	650		158	654	
Sep-12	148	93,744	633		287	646	
Oct-12	151	109,385	724		631	684	
Nov-12	151	175,449	1,162		970	1,093	
Dec-12	153	173,786	1,136	10,145	1,197	1,034	9,985
2013-F							9,542
2014-F							9,542
2015-F							9,542

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Old Crow Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	131	91,080	695		1,114	689	
Feb-08	131	104,191	795		955	763	
Mar-08	128	75,158	587		735	601	
Apr-08	134	76,598	572		517	565	
May-08	138	75,835	550		308	553	
Jun-08	139	77,827	560		226	542	
Jul-08	142	56,734	400		173	383	
Aug-08	143	76,254	533		188	527	
Sep-08	143	64,023	448		319	447	
Oct-08	140	57,323	409		563	403	
Nov-08	141	89,395	634		783	643	
Dec-08	139	77,918	561	6,743	1,186	502	
Jan-09	139	119,647	861		1,138	848	
Feb-09	136	87,509	643		955	611	
Mar-09	139	89,694	645		869	623	
Apr-09	141	91,451	649		515	643	
May-09	141	83,798	594		331	592	
Jun-09	144	71,199	494		144	499	
Jul-09	144	74,912	520		63	534	
Aug-09	141	57,483	408		158	410	
Sep-09	142	60,469	426		306	428	
Oct-09	142	84,122	592		542	592	
Nov-09	138	87,918	637		782	647	
Dec-09	137	80,345	586	7,057	943	594	
Jan-10	137	111,757	816		991	843	
Feb-10	137	93,880	685		679	728	
Mar-10	138	87,449	634		656	669	
Apr-10	138	103,587	751		461	759	
May-10	139	67,465	485		292	494	
Jun-10	140	61,879	442		172	439	
Jul-10	140	70,851	506		117	505	
Aug-10	139	57,504	414		146	419	
Sep-10	141	66,581	472		332	468	
Oct-10	141	84,042	596		520	602	
Nov-10	143	81,156	568		718	595	
Dec-10	140	89,309	638	7,006	1,163	585	7,105
Jan-11	141	147,202	1,044		1,010	1,066	
Feb-11	139	106,269	765		906	745	
Mar-11	137	93,778	685		902	653	
Apr-11	138	121,063	877		511	872	
May-11	140	96,075	686		296	693	
Jun-11	140	64,261	459		161	459	
Jul-11	139	76,307	549		128	545	
Aug-11	141	64,040	454		218	440	
Sep-11	140	73,293	524		329	520	
Nov-11	142	72,107	508		513	515	
Nov-11	139	79,743	574		936	541	
Dec-11	140	113,678	812	7,936	775	865	7,915
Jan-12	140	110,225	787		1,118	780	
Feb-12	143	104,490	731		708	765	
Mar-12	142	118,638	835		756	843	
Apr-12	142	93,954	662		451	673	
May-12	142	80,480	567		351	559	
Jun-12	138	81,250	589		200	578	
Jul-12	140	60,953	435		140	428	
Aug-12	142	83,331	587		158	589	
Sep-12	142	48,796	344		287	351	
Oct-12	145	72,356	499		631	474	
Nov-12	142	91,731	646		970	604	
Dec-12	143	112,281	785	7,467	1,197	723	7,370
2013-F							7,463
2014-F							7,463
2015-F							7,463

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Destruction Bay Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	96	69,839	727		1,114	723	
Feb-08	96	53,911	562		955	535	
Mar-08	96	58,923	614		735	625	
Apr-08	95	55,343	583		517	577	
May-08	95	49,769	524		308	527	
Jun-08	96	49,553	516		226	502	
Jul-08	97	39,916	412		173	398	
Aug-08	97	42,410	437		188	432	
Sep-08	97	40,477	417		319	417	
Oct-08	99	38,346	387		563	383	
Nov-08	99	55,145	557		783	565	
Dec-08	99	54,626	552	6,288	1,186	504	
Jan-09	97	72,543	748		1,138	738	
Feb-09	98	61,817	631		955	604	
Mar-09	98	58,039	592		869	574	
Apr-09	98	60,358	616		515	611	
May-09	97	45,668	471		331	469	
Jun-09	93	40,017	430		144	434	
Jul-09	95	42,419	447		63	458	
Aug-09	96	35,939	374		158	376	
Sep-09	97	43,929	453		306	455	
Oct-09	95	42,179	444		542	444	
Nov-09	92	51,709	562		782	570	
Dec-09	92	52,117	566	6,334	943	572	
Jan-10	93	77,387	832		991	854	
Feb-10	93	55,867	601		679	635	
Mar-10	94	48,574	517		656	545	
Apr-10	94	57,930	616		461	623	
May-10	98	50,648	517		292	523	
Jun-10	97	40,963	422		172	420	
Jul-10	97	42,640	440		117	439	
Aug-10	100	30,270	303		146	307	
Sep-10	99	44,632	451		332	447	
Oct-10	98	48,411	494		520	499	
Nov-10	95	55,968	589		718	611	
Dec-10	95	56,187	591	6,373	1,163	549	6,452
Jan-11	95	71,097	748		1,010	767	
Feb-11	95	69,550	732		906	716	
Mar-11	95	62,307	656		902	630	
Apr-11	97	60,626	625		511	621	
May-11	98	47,666	486		296	492	
Jun-11	100	44,866	449		161	449	
Jul-11	99	39,981	404		128	401	
Aug-11	100	39,974	400		218	388	
Sep-11	97	46,103	475		329	472	
Nov-11	98	49,678	507		513	513	
Nov-11	98	51,295	523		936	497	
Dec-11	97	70,724	729	6,735	775	772	6,718
Jan-12	98	81,478	831		1,118	826	
Feb-12	97	66,408	685		708	713	
Mar-12	97	67,243	693		756	700	
Apr-12	97	49,038	506		451	515	
May-12	96	43,666	455		351	449	
Jun-12	94	51,763	551		200	542	
Jul-12	95	41,417	436		140	430	
Aug-12	96	44,073	459		158	461	
Sep-12	94	41,900	446		287	452	
Oct-12	97	47,157	486		631	466	
Nov-12	97	55,766	575		970	541	
Dec-12	95	75,934	799	6,921	1,197	749	6,843
2013-F							6,671
2014-F							6,671
2015-F							6,671

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Beaver Creek Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	67	63,422	947		1,114	938	
Feb-08	67	66,785	997		955	948	
Mar-08	67	48,089	718		735	738	
Apr-08	68	49,702	731		517	721	
May-08	68	43,227	636		308	641	
Jun-08	67	40,688	607		226	581	
Jul-08	68	38,326	564		173	539	
Aug-08	68	43,814	644		188	635	
Sep-08	67	35,662	532		319	531	
Oct-08	67	41,349	617		563	608	
Nov-08	66	50,959	772		783	786	
Dec-08	67	67,800	1,012	8,776	1,186	924	
Jan-09	67	63,353	946		1,138	927	
Feb-09	66	61,046	925		955	876	
Mar-09	66	55,035	834		869	800	
Apr-09	68	50,396	741		515	732	
May-09	68	39,722	584		331	580	
Jun-09	68	33,934	499		144	506	
Jul-09	67	40,837	610		63	630	
Aug-09	67	39,459	589		158	592	
Sep-09	67	39,571	591		306	594	
Oct-09	66	45,651	692		542	691	
Nov-09	67	52,749	787		782	802	
Dec-09	67	56,705	846	8,643	943	857	
Jan-10	67	73,461	1,096		991	1,138	
Feb-10	67	58,718	876		679	940	
Mar-10	65	53,024	816		656	868	
Apr-10	67	49,783	743		461	756	
May-10	67	46,506	694		292	706	
Jun-10	68	38,372	564		172	560	
Jul-10	67	40,978	612		117	610	
Aug-10	65	40,940	630		146	638	
Sep-10	66	37,510	568		332	561	
Oct-10	66	43,699	662		520	671	
Nov-10	66	44,720	678		718	718	
Dec-10	66	51,924	787	8,726	1,163	708	8,874
Jan-11	65	73,657	1,133		1,010	1,167	
Feb-11	67	58,086	867		906	838	
Mar-11	67	58,001	866		902	818	
Apr-11	68	49,251	724		511	717	
May-11	68	41,615	612		296	622	
Jun-11	69	36,805	533		161	533	
Jul-11	69	41,654	604		128	598	
Aug-11	69	41,815	606		218	585	
Sep-11	68	40,426	595		329	589	
Nov-11	68	45,834	674		513	685	
Nov-11	72	63,796	886		936	837	
Dec-11	71	74,507	1,049	9,149	775	1,129	9,119
Jan-12	71	78,077	1,100		1,118	1,089	
Feb-12	71	64,051	902		708	954	
Mar-12	71	61,206	862		756	874	
Apr-12	72	48,111	668		451	686	
May-12	72	46,435	645		351	633	
Jun-12	69	45,435	658		200	643	
Jul-12	71	39,794	560		140	549	
Aug-12	71	43,174	608		158	611	
Sep-12	71	42,305	596		287	607	
Oct-12	71	50,852	716		631	679	
Nov-12	72	62,837	873		970	811	
Dec-12	71	75,071	1,057	9,246	1,197	965	9,101
2013-F							9,031
2014-F							9,031
2015-F							9,031

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Tagish Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	328	173,641	529		1,114	524	
Feb-08	325	196,641	605		955	577	
Mar-08	326	134,643	413		735	425	
Apr-08	328	111,708	341		517	335	
May-08	333	96,449	290		308	293	
Jun-08	334	94,007	281		226	266	
Jul-08	336	90,493	269		173	255	
Aug-08	338	107,999	320		188	314	
Sep-08	338	99,082	293		319	292	
Oct-08	335	106,242	317		563	312	
Nov-08	328	160,587	490		783	498	
Dec-08	326	166,814	512	4,660	1,186	460	
Jan-09	322	221,788	689		1,138	678	
Feb-09	324	180,403	557		955	528	
Mar-09	303	148,681	491		869	471	
Apr-09	306	130,333	426		515	421	
May-09	339	98,861	292		331	289	
Jun-09	340	91,995	271		144	275	
Jul-09	333	107,399	323		63	335	
Aug-09	342	96,059	281		158	283	
Sep-09	341	103,660	304		306	306	
Oct-09	341	131,419	385		542	385	
Nov-09	329	148,515	451		782	460	
Dec-09	327	167,723	513	4,982	943	519	
Jan-10	328	207,053	631		991	655	
Feb-10	313	160,188	512		679	549	
Mar-10	321	136,527	425		656	456	
Apr-10	324	137,314	424		461	431	
May-10	334	117,245	351		292	358	
Jun-10	338	95,130	281		172	279	
Jul-10	343	108,576	317		117	316	
Aug-10	338	105,213	311		146	316	
Sep-10	324	108,883	336		332	332	
Oct-10	341	141,371	415		520	419	
Nov-10	334	139,277	417		718	441	
Dec-10	330	177,134	537	4,957	1,163	491	5,043
Jan-11	330	241,159	731		1,010	750	
Feb-11	328	170,902	521		906	504	
Mar-11	331	181,387	548		902	520	
Apr-11	332	130,345	393		511	388	
May-11	321	117,122	365		296	371	
Jun-11	342	97,953	286		161	286	
Jul-11	339	109,873	324		128	321	
Aug-11	343	108,934	318		218	305	
Sep-11	345	118,489	343		329	340	
Nov-11	343	124,107	362		513	368	
Nov-11	341	176,455	517		936	489	
Dec-11	333	164,591	494	5,202	775	540	5,185
Jan-12	332	232,663	701		1,118	695	
Feb-12	331	167,948	507		708	538	
Mar-12	335	169,143	505		756	512	
Apr-12	337	116,598	346		451	356	
May-12	338	118,998	352		351	345	
Jun-12	344	119,871	348		200	339	
Jul-12	348	109,618	315		140	309	
Aug-12	347	119,515	344		158	346	
Sep-12	346	115,503	334		287	340	
Oct-12	347	143,731	414		631	393	
Nov-12	344	176,497	513		970	477	
Dec-12	344	219,318	638	5,318	1,197	584	5,233
2013-F							5,154
2014-F							5,154
2015-F							5,154

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Marsh Lake Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	411	400,772	975		1,114	965	
Feb-08	410	391,831	956		955	899	
Mar-08	410	298,424	728		735	752	
Apr-08	412	271,266	658		517	647	
May-08	416	218,708	526		308	532	
Jun-08	419	204,232	487		226	457	
Jul-08	421	198,238	471		173	442	
Aug-08	420	233,573	556		188	546	
Sep-08	422	218,657	518		319	517	
Oct-08	419	248,762	594		563	583	
Nov-08	417	352,172	845		783	861	
Dec-08	413	443,500	1,074	8,387	1,186	971	
Jan-09	414	440,749	1,065		1,138	1,043	
Feb-09	411	377,505	919		955	861	
Mar-09	377	321,118	852		869	812	
Apr-09	407	311,581	766		515	755	
May-09	401	200,880	501		331	497	
Jun-09	420	207,457	494		144	502	
Jul-09	420	211,095	503		63	527	
Aug-09	425	200,538	472		158	475	
Sep-09	427	238,803	559		306	564	
Oct-09	428	261,931	612		542	612	
Nov-09	422	325,639	772		782	789	
Dec-09	416	417,792	1,004	8,517	943	1,017	
Jan-10	418	412,629	987		991	1,035	
Feb-10	411	333,347	811		679	885	
Mar-10	414	305,475	738		656	799	
Apr-10	424	300,073	708		461	723	
May-10	430	241,376	561		292	576	
Jun-10	426	201,491	473		172	468	
Jul-10	428	224,800	525		117	523	
Aug-10	423	210,803	498		146	508	
Sep-10	398	247,409	622		332	613	
Oct-10	430	288,653	671		520	681	
Nov-10	420	319,900	762		718	809	
Dec-10	422	418,397	991	8,348	1,163	900	8,520
Jan-11	419	533,507	1,273		1,010	1,312	
Feb-11	422	386,539	916		906	882	
Mar-11	422	395,398	937		902	882	
Apr-11	424	329,571	777		511	769	
May-11	427	258,919	606		296	619	
Jun-11	430	222,281	517		161	517	
Jul-11	432	211,742	490		128	483	
Aug-11	433	241,652	558		218	533	
Sep-11	434	253,323	584		329	577	
Nov-11	434	285,632	658		513	671	
Nov-11	433	378,486	874		936	817	
Dec-11	429	463,859	1,081	9,272	775	1,174	9,237
Jan-12	429	481,362	1,122		1,118	1,110	
Feb-12	427	418,969	981		708	1,042	
Mar-12	429	349,356	814		756	828	
Apr-12	429	271,112	632		451	652	
May-12	432	274,383	635		351	621	
Jun-12	430	226,538	527		200	508	
Jul-12	436	222,070	509		140	496	
Aug-12	431	251,460	583		158	587	
Sep-12	434	242,318	558		287	572	
Oct-12	435	305,434	702		631	659	
Nov-12	436	414,188	950		970	877	
Dec-12	433	560,428	1,294	9,309	1,197	1,186	9,140
2013-F							8,966
2014-F							8,966
2015-F							8,966

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Deep Creek Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	37	24,787	670		1,114	662	
Feb-08	38	24,484	644		955	601	
Mar-08	37	17,183	464		735	483	
Apr-08	37	15,980	432		517	423	
May-08	38	15,025	395		308	401	
Jun-08	39	11,658	299		226	275	
Jul-08	39	12,112	311		173	289	
Aug-08	40	14,232	356		188	348	
Sep-08	42	12,710	303		319	301	
Oct-08	40	11,303	283		563	275	
Nov-08	39	20,333	521		783	534	
Dec-08	40	20,697	517		1,186	439	
Jan-09	41	32,952	804		1,138	787	
Feb-09	41	18,170	443		955	399	
Mar-09	41	19,576	477		869	447	
Apr-09	42	11,396	271		515	263	
May-09	43	9,670	225		331	222	
Jun-09	42	11,584	276		144	282	
Jul-09	42	12,300	293		63	311	
Aug-09	42	11,644	277		158	280	
Sep-09	42	14,440	344		306	347	
Oct-09	42	14,789	352		542	352	
Nov-09	42	14,177	338		782	350	
Dec-09	42	14,316	341		943	350	
Jan-10	42	25,129	598		991	635	
Feb-10	41	15,883	387		679	444	
Mar-10	41	15,309	373		656	420	
Apr-10	41	17,914	437		461	449	
May-10	41	13,301	324		292	335	
Jun-10	43	12,054	280		172	276	
Jul-10	43	13,540	315		117	313	
Aug-10	42	12,057	287		146	294	
Sep-10	42	15,199	362		332	356	
Oct-10	42	16,102	383		520	391	
Nov-10	40	16,312	408		718	444	
Dec-10	41	19,783	483		1,163	412	4,770
Jan-11	41	28,824	703		1,010	733	
Feb-11	41	23,823	581		906	555	
Mar-11	40	29,345	734		902	691	
Apr-11	40	20,711	518		511	511	
May-11	41	16,103	393		296	402	
Jun-11	41	13,371	326		161	326	
Jul-11	40	11,214	280		128	275	
Aug-11	40	11,380	285		218	266	
Sep-11	40	15,078	377		329	372	
Nov-11	40	17,801	445		513	455	
Nov-11	41	20,634	503		936	460	
Dec-11	40	26,335	658		775	729	5,776
Jan-12	40	29,792	745		1,118	735	
Feb-12	40	30,462	762		708	808	
Mar-12	40	25,713	643		756	653	
Apr-12	40	21,670	542		451	557	
May-12	41	14,455	353		351	342	
Jun-12	41	12,317	300		200	286	
Jul-12	41	12,535	306		140	296	
Aug-12	41	15,324	374		158	377	
Sep-12	41	13,638	333		287	343	
Oct-12	40	14,883	372		631	339	
Nov-12	41	20,978	512		970	456	
Dec-12	40	27,516	688		1,197	605	5,798
2013-F							5,448
2014-F							5,448
2015-F							5,448

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Lower Post BC Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	69	78,905	1,144		1,300	1,125	
Feb-08	69	68,474	992		1,064	943	
Mar-08	68	53,857	792		833	790	
Apr-08	65	60,271	927		554	911	
May-08	68	44,158	649		296	650	
Jun-08	67	39,130	584		191	562	
Jul-08	66	37,269	565		132	549	
Aug-08	66	40,803	618		154	615	
Sep-08	65	37,607	579		304	574	
Oct-08	67	50,114	748		524	750	
Nov-08	66	54,570	827		879	825	
Dec-08	68	57,920	852	9,277	1,387	743	
Jan-09	68	91,464	1,345		1,329	1,316	
Feb-09	69	69,890	1,013		1,090	955	
Mar-09	70	67,233	960		1,054	881	
Apr-09	70	58,502	836		590	806	
May-09	70	44,936	642		356	622	
Jun-09	69	36,937	535		131	535	
Jul-09	70	44,160	631		89	630	
Aug-09	69	38,613	560		134	563	
Sep-09	69	46,655	676		279	680	
Oct-09	70	48,356	691		607	663	
Nov-09	70	55,125	788		997	745	
Dec-09	70	66,854	955	9,631	1,274	886	
Jan-10	70	86,749	1,239		1,141	1,276	
Feb-10	70	63,002	900		966	886	
Mar-10	64	49,267	770		764	793	
Apr-10	64	57,924	905		503	906	
May-10	64	46,119	721		278	728	
Jun-10	63	35,115	557		143	553	
Jul-10	64	32,961	515		71	521	
Aug-10	64	33,016	516		120	524	
Sep-10	65	38,150	587		320	577	
Oct-10	64	41,769	653		517	657	
Nov-10	62	47,559	767		904	757	
Dec-10	62	60,859	982	9,111	1,292	906	9,082
Jan-11	61	79,221	1,299		1,201	1,315	
Feb-11	62	53,257	859		1,005	831	
Mar-11	62	62,675	1,011		1,033	939	
Apr-11	61	44,109	723		588	695	
May-11	61	41,547	681		271	690	
Jun-11	61	37,373	613		143	608	
Jul-11	59	31,949	542		104	536	
Aug-11	59	34,837	590		195	573	
Sep-11	59	44,969	762		292	761	
Nov-11	61	39,770	652		512	658	
Nov-11	63	43,401	689		1,059	624	
Dec-11	63	56,750	901	9,321	1,006	925	9,155
Jan-12	63	74,774	1,187		1,273	1,178	
Feb-12	63	56,636	899		936	895	
Mar-12	63	55,930	888		909	859	
Apr-12	63	44,857	712		513	710	
May-12	62	42,971	693		340	678	
Jun-12	50	24,336	487		150	480	
Jul-12	63	37,116	589		78	592	
Aug-12	63	37,366	593		134	597	
Sep-12	63	22,846	363		259	373	
Oct-12	63	39,603	629		715	563	
Nov-12	56	43,671	780		1,113	696	
Dec-12	55	51,513	937	8,755	1,356	838	8,461
2013-F							8,899
2014-F							8,899
2015-F							8,899

Yukon Electrical Company Limited
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Upper Liard Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	64	65,667	1,026		1,300	1,010	
Feb-08	64	55,952	874		1,064	832	
Mar-08	63	41,649	661		833	660	
Apr-08	64	48,021	750		554	736	
May-08	65	29,073	447		296	448	
Jun-08	63	30,915	491		191	472	
Jul-08	63	34,030	540		132	527	
Aug-08	62	32,475	524		154	521	
Sep-08	63	35,568	565		304	560	
Oct-08	63	39,219	623		524	624	
Nov-08	63	39,430	626		879	625	
Dec-08	62	45,300	731	7,857	1,387	636	
Jan-09	62	71,230	1,149		1,329	1,124	
Feb-09	60	47,313	789		1,090	739	
Mar-09	61	52,291	857		1,054	789	
Apr-09	63	39,506	627		590	602	
May-09	64	44,628	697		356	680	
Jun-09	66	36,490	553		131	553	
Jul-09	66	31,727	481		89	480	
Aug-09	66	34,460	522		134	525	
Sep-09	66	34,956	530		279	533	
Oct-09	66	37,878	574		607	550	
Nov-09	65	45,540	701		997	664	
Dec-09	66	57,158	866	8,345	1,274	806	
Jan-10	66	68,432	1,037		1,141	1,069	
Feb-10	66	49,027	743		966	730	
Mar-10	66	50,961	772		764	792	
Apr-10	66	42,611	646		503	647	
May-10	66	35,222	534		278	540	
Jun-10	65	36,941	568		143	564	
Jul-10	66	32,762	496		71	501	
Aug-10	66	33,090	501		120	509	
Sep-10	63	33,518	532		320	523	
Oct-10	66	43,196	654		517	658	
Nov-10	66	42,270	640		904	632	
Dec-10	66	49,302	747	7,871	1,292	681	7,846
Jan-11	66	65,174	987		1,201	1,002	
Feb-11	65	47,235	727		1,005	702	
Mar-11	65	55,862	859		1,033	797	
Apr-11	65	39,282	604		588	580	
May-11	65	45,187	695		271	703	
Jun-11	64	31,926	499		143	495	
Jul-11	65	30,256	465		104	460	
Aug-11	65	34,251	527		195	511	
Sep-11	64	35,069	548		292	547	
Nov-11	65	39,130	602		512	607	
Nov-11	66	43,275	656		1,059	600	
Dec-11	66	47,885	726	7,896	1,006	747	7,752
Jan-12	66	65,790	997		1,273	989	
Feb-12	65	45,125	694		936	691	
Mar-12	66	47,560	721		909	696	
Apr-12	66	41,107	623		513	621	
May-12	66	38,426	582		340	569	
Jun-12	52	26,859	517		150	510	
Jul-12	63	29,214	464		78	467	
Aug-12	54	28,439	527		134	530	
Sep-12	53	28,120	531		259	540	
Oct-12	54	37,584	696		715	640	
Nov-12	54	40,378	748		1,113	676	
Dec-12	53	48,824	921	8,019	1,356	836	7,764
2013-F							7,787
2014-F							7,787
2015-F							7,787

Yukon Electrical Company Limited
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Watson Lake Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	577	648,227	1,123		1,300	1,105	
Feb-08	575	593,667	1,032		1,064	984	
Mar-08	576	480,732	835		833	833	
Apr-08	577	440,734	764		554	747	
May-08	583	400,179	686		296	687	
Jun-08	585	331,773	567		191	546	
Jul-08	584	344,932	591		132	575	
Aug-08	580	346,512	597		154	594	
Sep-08	585	346,036	592		304	587	
Oct-08	583	384,942	660		524	662	
Nov-08	575	483,711	841		879	840	
Dec-08	574	534,507	931	9,220	1,387	823	
Jan-09	581	663,093	1,141		1,329	1,113	
Feb-09	576	542,567	942		1,090	885	
Mar-09	576	499,062	866		1,054	788	
Apr-09	579	469,583	811		590	782	
May-09	589	389,486	661		356	641	
Jun-09	588	335,714	571		131	571	
Jul-09	580	348,504	601		89	600	
Aug-09	585	316,605	541		134	545	
Sep-09	583	362,886	622		279	626	
Oct-09	586	389,773	665		607	638	
Nov-09	584	455,989	781		997	738	
Dec-09	580	559,479	965	9,168	1,274	896	
Jan-10	579	632,709	1,093		1,141	1,130	
Feb-10	583	502,123	861		966	847	
Mar-10	587	458,172	781		764	803	
Apr-10	589	447,028	759		503	760	
May-10	590	382,172	648		278	655	
Jun-10	594	345,986	582		143	578	
Jul-10	588	335,565	571		71	576	
Aug-10	591	312,521	529		120	537	
Sep-10	590	359,939	610		320	600	
Oct-10	589	433,353	736		517	740	
Nov-10	595	443,539	745		904	735	
Dec-10	594	541,796	912	8,827	1,292	837	8,798
Jan-11	589	676,027	1,148		1,201	1,164	
Feb-11	591	523,769	886		1,005	858	
Mar-11	590	573,573	972		1,033	901	
Apr-11	592	490,322	828		588	800	
May-11	591	403,160	682		271	691	
Jun-11	594	364,889	614		143	610	
Jul-11	593	324,189	547		104	541	
Aug-11	594	336,216	566		195	548	
Sep-11	595	382,102	642		292	641	
Nov-11	594	397,049	668		512	674	
Nov-11	595	472,744	795		1,059	730	
Dec-11	593	548,323	925	9,273	1,006	949	9,108
Jan-12	594	667,785	1,124		1,273	1,115	
Feb-12	595	556,057	935		936	931	
Mar-12	594	514,187	866		909	837	
Apr-12	595	463,297	779		513	776	
May-12	590	419,114	710		340	696	
Jun-12	594	383,194	645		150	638	
Jul-12	589	346,701	589		78	592	
Aug-12	590	337,766	572		134	576	
Sep-12	590	332,985	564		259	575	
Oct-12	592	408,486	690		715	625	
Nov-12	595	460,221	773		1,113	691	
Dec-12	588	589,415	1,002	9,250	1,356	905	8,957
2013-F							8,954
2014-F							8,954
2015-F							8,954

Yukon Electrical Company Limited
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Keno City

Residential		**Energy (kWh)**		**(Whitehorse)**	**Annual**
monthly	**Customers**	**(Billed)**	**UPC (kWh)**	**MHDD**	**UPC (kWh)**
Jan-08	41	10,684	261	1,114	
Feb-08	41	12,628	308	955	
Mar-08	41	9,590	234	735	
Apr-08	40	12,167	304	517	
May-08	40	8,520	213	308	
Jun-08	41	5,939	145	226	
Jul-08	43	7,442	173	173	
Aug-08	42	11,599	276	188	
Sep-08	43	18,022	419	319	
Oct-08	43	17,099	398	563	
Nov-08	41	16,922	413	783	
Dec-08	40	23,060	577	1,186	
Jan-09	40	26,389	660	1,138	
Feb-09	40	11,784	295	955	
Mar-09	39	22,181	569	869	
Apr-09	41	13,250	323	515	
May-09	42	10,385	247	331	
Jun-09	42	7,458	178	144	
Jul-09	41	7,665	187	63	
Aug-09	42	7,579	180	158	
Sep-09	42	10,555	251	306	
Oct-09	41	12,095	295	542	
Nov-09	41	14,760	360	782	
Dec-09	41	15,725	384	943	
Jan-10	40	15,876	397	991	
Feb-10	39	12,949	332	679	
Mar-10	41	17,108	417	656	
Apr-10	39	13,401	344	461	
May-10	39	14,352	368	292	
Jun-10	40	5,109	128	172	
Jul-10	42	7,757	185	117	
Aug-10	42	8,430	201	146	
Sep-10	37	15,799	427	332	
Oct-10	37	16,490	446	520	
Nov-10	37	21,169	572	718	
Dec-10	37	21,264	575	1,163	4,390
Jan-11	37	21,762	588	1,010	
Feb-11	37	15,975	432	906	
Mar-11	37	22,527	609	902	
Apr-11	37	12,643	342	511	
May-11	39	13,354	342	296	
Jun-11	40	9,177	229	161	
Jul-11	40	13,430	336	128	
Aug-11	40	5,610	140	218	
Sep-11	40	13,729	343	329	
Nov-11	39	17,437	447	513	
Nov-11	39	18,395	472	936	
Dec-11	39	24,991	641	775	4,921
Jan-12	39	14,009	359	1,118	
Feb-12	39	15,827	406	708	
Mar-12	39	18,224	467	756	
Apr-12	39	15,467	397	451	
May-12	39	14,896	382	351	
Jun-12	40	11,732	293	200	
Jul-12	41	8,147	199	140	
Aug-12	41	9,042	221	158	
Sep-12	41	13,623	332	287	
Oct-12	41	18,789	458	631	
Nov-12	41	23,219	566	970	
Dec-12	41	19,709	481	1,197	4,561
2013-F					4,624
2014-F					4,624
2015-F					4,624

Yukon Electrical Company Limited
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Stewart Crossing

Residential		Energy (kWh)		(Watson Lake)	Annual
monthly	Customers	(Billed)	UPC (kWh)	MHDD	UPC (kWh)
Jan-08	16	17,369	1,086	1,300	
Feb-08	16	13,973	873	1,064	
Mar-08	16	14,366	898	833	
Apr-08	16	6,755	422	554	
May-08	16	8,767	548	296	
Jun-08	16	8,525	533	191	
Jul-08	16	4,801	300	132	
Aug-08	16	10,261	641	154	
Sep-08	16	7,475	467	304	
Oct-08	16	11,318	707	524	
Nov-08	16	9,990	624	879	
Dec-08	16	11,591	724	1,387	
Jan-09	16	18,151	1,134	1,329	
Feb-09	15	14,671	978	1,090	
Mar-09	16	10,749	672	1,054	
Apr-09	16	13,478	842	590	
May-09	16	8,685	543	356	
Jun-09	16	7,853	491	131	
Jul-09	15	9,445	630	89	
Aug-09	16	9,893	618	134	
Sep-09	15	9,629	642	279	
Oct-09	15	9,321	621	607	
Nov-09	16	10,917	682	997	
Dec-09	16	11,386	712	1,274	
Jan-10	15	15,541	1,036	1,141	
Feb-10	15	10,010	667	966	
Mar-10	15	10,503	700	764	
Apr-10	14	9,279	663	503	
May-10	15	9,048	603	278	
Jun-10	15	6,189	413	143	
Jul-10	15	7,388	493	71	
Aug-10	15	6,691	446	120	
Sep-10	14	7,628	545	320	
Oct-10	15	4,687	312	517	
Nov-10	15	11,788	786	904	
Dec-10	15	12,259	817	1,292	7,481
Jan-11	14	16,136	1,153	1,201	
Feb-11	15	12,698	847	1,005	
Mar-11	15	12,688	846	1,033	
Apr-11	15	11,864	791	588	
May-11	13	11,444	880	271	
Jun-11	15	5,145	343	143	
Jul-11	14	10,057	718	104	
Aug-11	15	7,866	524	195	
Sep-11	15	9,042	603	292	
Nov-11	15	8,373	558	512	
Nov-11	14	9,394	671	1,059	
Dec-11	12	9,687	807	1,006	8,741
Jan-12	14	17,927	1,281	1,273	
Feb-12	14	10,857	776	936	
Mar-12	14	11,904	850	909	
Apr-12	14	6,044	432	513	
May-12	14	7,985	570	340	
Jun-12	13	8,134	626	150	
Jul-12	14	6,532	467	78	
Aug-12	14	8,450	604	134	
Sep-12	14	6,204	443	259	
Oct-12	14	7,225	516	715	
Nov-12	13	13,038	1,003	1,113	
Dec-12	13	13,024	1,002	1,356	8,568
2013-F				1,218	8,264
2014-F				1,218	8,264
2015-F				1,218	8,264

Yukon Electrical Company Limited
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Swift River Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	3	4,316	1,439	1,114	
Feb-08	3	4,144	1,381	955	
Mar-08	3	3,160	1,053	735	
Apr-08	3	4,617	1,539	517	
May-08	3	2,000	667	308	
Jun-08	3	2,133	711	226	
Jul-08	3	2,395	798	173	
Aug-08	3	2,135	712	188	
Sep-08	3	2,375	792	319	
Oct-08	3	2,555	852	563	
Nov-08	3	3,005	1,002	783	
Dec-08	3	3,616	1,205	1,186	
Jan-09	3	5,435	1,812	1,138	
Feb-09	3	3,871	1,290	955	
Mar-09	3	4,909	1,636	869	
Apr-09	3	4,224	1,408	515	
May-09	3	4,128	1,376	331	
Jun-09	3	3,610	1,203	144	
Jul-09	3	3,383	1,128	63	
Aug-09	3	3,324	1,108	158	
Sep-09	3	3,430	1,143	306	
Oct-09	3	2,460	820	542	
Nov-09	3	2,460	820	782	
Dec-09	3	2,500	833	943	
Jan-10	2	2,029	1,015	991	
Feb-10	2	1,720	860	679	
Mar-10	2	1,619	810	656	
Apr-10	1	780	780	461	
May-10	2	929	464	292	
Jun-10	3	929	310	172	
Jul-10	3	369	123	117	
Aug-10	2	1,050	525	146	
Sep-10	2	1,134	567	332	
Oct-10	2	903	452	520	
Nov-10	2	2,100	1,050	718	
Dec-10	2	3,113	1,557	1,163	8,511
Jan-11	2	3,226	1,613	1,010	
Feb-11	2	2,072	1,036	906	
Mar-11	2	2,087	1,044	902	
Apr-11	2	3,707	1,854	511	
May-11	2	1,502	751	296	
Jun-11	2	1,129	565	161	
Jul-11	2	1,061	531	128	
Aug-11	2	1,309	655	218	
Sep-11	2	1,281	641	329	
Nov-11	2	1,666	833	513	
Nov-11	2	2,275	1,138	936	
Dec-11	2	2,252	1,126	775	11,784
Jan-12	2	2,851	1,426	1,118	
Feb-12	2	2,307	1,154	708	
Mar-12	2	2,062	1,031	756	
Apr-12	2	2,028	1,014	451	
May-12	2	(2,714)	(1,357)	351	
Jun-12	2	1,739	870	200	
Jul-12	2	1,487	744	140	
Aug-12	2	1,548	774	158	
Sep-12	2	1,608	804	287	
Oct-12	2	1,343	672	631	
Nov-12	2	2,061	1,031	970	
Dec-12	2	1,785	893	1,197	9,053
2013-F				1,045	9,782
2014-F				1,045	9,782
2015-F				1,045	9,782

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Watson Lake
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	930.6	1,266.0	938.7	1,605.2	1,406.6	1,409.7	1,350.2	1,344.8	1,043.4	1,246.3	1,177.5	1,365.6	1,330.3	1,185.2	1,102.4	1,300.1	1,329.3	1,141.4	1,201.0	1,273.0	**1,247.4**
FEB	752.4	119.4	941.9	947.3	884.8	942.0	1,066.4	956.0	1,031.0	970.3	964.7	881.2	941.8	1,016.7	1,017.3	1,064.2	1,089.5	965.8	1,004.6	935.5	**924.6**
MAR	573.0	24.3	855.6	874.3	943.9	843.4	871.4	750.1	844.9	991.6	899.5	809.9	726.9	960.5	1,001.9	833.3	1,054.2	763.5	1,032.9	909.0	**828.2**
APR	347.3	50.1	492.7	547.7	527.9	500.1	506.4	590.9	535.8	694.8	554.4	497.4	464.8	528.2	543.0	554.0	590.0	502.7	587.5	512.6	**506.4**
MAY	190.5	21.8	242.5	366.4	311.8	211.0	372.2	373.8	366.6	365.9	341.6	292.3	256.9	371.1	332.2	295.6	356.0	277.7	271.1	340.2	**297.9**
JUN	99.2	0.8	97.0	163.9	142.6	89.0	140.2	158.0	155.5	147.8	179.9	74.1	126.6	136.5	122.6	191.0	130.6	142.7	143.1	149.7	**129.5**
JUL	83.2	1.2	113.0	103.3	84.1	65.7	99.4	84.3	120.3	121.6	56.6	35.6	136.9	79.2	88.6	131.5	89.0	70.8	104.4	77.8	**87.3**
AUG	66.0	2.3	189.9	185.1	109.6	156.8	127.8	216.9	120.6	181.5	163.0	145.7	162.2	171.7	143.1	154.0	134.4	119.6	195.1	134.0	**144.0**
SEP	298.4	38.8	224.9	354.7	271.1	320.7	292.5	314.8	299.6	331.0	330.2	370.7	297.3	292.4	314.7	304.2	279.4	319.7	292.4	259.4	**290.3**
OCT	248.2	89.8	552.7	662.2	659.7	561.2	519.8	575.8	577.0	514.8	526.1	565.0	541.7	543.3	553.1	523.5	606.9	516.8	511.9	714.5	**528.2**
NOV	127.3	59.4	1,000.2	1,121.2	935.8	958.1	939.9	858.4	975.0	821.9	963.9	875.5	758.4	1,196.2	956.6	879.0	996.5	904.2	1,059.1	1,112.8	**875.0**
DEC	22.1	122.5	1,295.4	1,361.1	983.7	1,252.7	1,013.0	1,222.8	1,275.4	1,117.9	1,095.5	1,070.7	1,061.0	1,050.0	1,255.1	1,386.5	1,273.7	1,292.1	1,006.3	1,356.2	**1,075.7**
TOTAL	**3,738.2**	**1,796.4**	**6,944.5**	**8,292.4**	**7,261.6**	**7,310.4**	**7,299.2**	**7,446.6**	**7,345.1**	**7,505.4**	**7,252.9**	**6,983.7**	**6,804.8**	**7,531.0**	**7,430.6**	**7,616.9**	**7,929.5**	**7,017.0**	**7,409.4**	**7,774.7**	**6,934.5**

Residential Regression Results (YECL 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

Residential (Carmacks)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.848334198
R Square	0.719670911
Adjusted R Square	0.718096029
Standard Error	137.0322957
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8580876.545	8580876.545	456.9679975	4.88748E-51
Residual	178	3342457.313	18777.85007		
Total	179	11923333.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	523.0507986	19.82511653	26.38323956	2.06292E-63	483.9282934	562.1733039	483.9282934	562.1733039
WH-HDD	0.66162154	0.030950434	21.37680981	4.88748E-51	0.600544547	0.722698534	0.600544547	0.722698534

Residential (Carcross)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.73085291
R Square	0.534145976
Adjusted R Square	0.531528819
Standard Error	100.3552824
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2055467.372	2055467.372	204.0939414	2.42352E-31
Residual	178	1792670.521	10071.1827		
Total	179	3848137.893			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	419.1099542	14.51887788	28.86655275	4.6941E-69	390.4586787	447.7612298	390.4586787	447.7612298
WH-HDD	0.323816596	0.022666478	14.28614509	2.42352E-31	0.279087002	0.36854619	0.279087002	0.36854619

Residential (Haines Junction)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.826511766
R Square	0.683121699
Adjusted R Square	0.681341483
Standard Error	70.97827216
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1933198.401	1933198.401	383.7298477	2.73648E-46
Residual	178	896748.8911	5037.915119		
Total	179	2829947.292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	493.5031661	10.26876554	48.0586653	7.1519E-104	473.2389809	513.7673514	473.2389809	513.7673514
WH-HDD	0.31403787	0.016031318	19.58902365	2.73648E-46	0.282401974	0.345673766	0.282401974	0.345673766

Residential (Teslin)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.774809495
R Square	0.600329753
Adjusted R Square	0.598084415
Standard Error	80.08503489
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1714789.401	1714789.401	267.3671534	2.73398E-37
Residual	178	1141623.081	6413.612813		
Total	179	2856412.482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	401.3105811	11.58628439	34.63669349	5.10981E-81	378.4464294	424.1747328	378.4464294	424.1747328
WH-HDD	0.295766652	0.018088193	16.35136549	2.73398E-37	0.260071758	0.331461545	0.260071758	0.331461545

Residential (Ross River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.816954541
R Square	0.667414722
Adjusted R Square	0.665546265
Standard Error	99.84467893
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3560923.245	3560923.245	357.2010799	2.05162E-44
Residual	178	1774474.864	9968.959911		
Total	179	5335398.109			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	420.6644462	14.44500644	29.12179014	1.28614E-69	392.1589471	449.1699452	392.1589471	449.1699452
WH-HDD	0.426211453	0.022551152	18.89976402	2.05162E-44	0.381709441	0.470713465	0.381709441	0.470713465

Residential (Pelly Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.814590942
R Square	0.663558403
Adjusted R Square	0.661668282
Standard Error	106.1935622
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3959003.162	3959003.162	351.0665651	5.74021E-44
Residual	178	2007318.933	11277.07266		
Total	179	5966322.096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	526.6014045	15.3635297	34.27606902	2.58572E-80	496.2833092	556.9194997	496.2833092	556.9194997
WH-HDD	0.449403793	0.023985126	18.7367704	5.74021E-44	0.402072005	0.496735581	0.402072005	0.496735581

Residential (Old Crow)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.700799321
R Square	0.491119688
Adjusted R Square	0.48826081
Standard Error	91.97982219
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1453372.136	1453372.136	171.7875549	6.55924E-28
Residual	178	1505931.209	8460.28769		
Total	179	2959303.345			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	431.2915805	13.30716006	32.41049018	1.39504E-76	405.0314857	457.5516753	405.0314857	457.5516753
WH-HDD	0.272290334	0.020774777	13.10677515	6.55924E-28	0.231293786	0.313286881	0.231293786	0.313286881

Residential (Destruction Bay)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.709031239
R Square	0.502725298
Adjusted R Square	0.49993162
Standard Error	72.69183708
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	950879.8973	950879.8973	179.9510466	8.32101E-29
Residual	178	940570.3656	5284.103178		
Total	179	1891450.263			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	383.8946	10.51667516	36.50341902	1.40822E-84	363.1411947	404.6480054	363.1411947	404.6480054
WH-HDD	0.220245296	0.016418348	13.41458336	8.32101E-29	0.187845643	0.25264495	0.187845643	0.25264495

Residential (Beaver Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.840637508
R Square	0.706671419
Adjusted R Square	0.705023506
Standard Error	87.03187359
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3248177.952	3248177.952	428.8280135	2.78648E-49
Residual	178	1348269.37	7574.547021		
Total	179	4596447.322			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	483.8810515	12.59131671	38.4297419	4.15449E-88	459.0335882	508.7285147	459.0335882	508.7285147
WH-HDD	0.407064957	0.019657222	20.70816297	2.78648E-49	0.368273771	0.445856142	0.368273771	0.445856142

Residential (Tagish)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77755681
R Square	0.604594592
Adjusted R Square	0.602373213
Standard Error	63.68762658
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1103956.052	1103956.052	272.1708788	1.04861E-37
Residual	178	721988.2526	4056.113779		
Total	179	1825944.304			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	234.2954311	9.213993033	25.42821883	3.71752E-61	216.1127137	252.4781485	216.1127137	252.4781485
WH-HDD	0.237312001	0.014384636	16.49760221	1.04861E-37	0.208925636	0.265698366	0.208925636	0.265698366

Residential (Marsh Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.873151604
R Square	0.762393723
Adjusted R Square	0.761058856
Standard Error	88.06938915
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4429873.997	4429873.997	571.1384587	1.93035E-57
Residual	178	1380606.68	7756.217305		
Total	179	5810480.677			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	386.6155856	12.74141904	30.3432125	2.9027E-72	361.4719133	411.7592579	361.4719133	411.7592579
WH-HDD	0.475378456	0.019891558	23.89850327	1.93035E-57	0.436124837	0.514632075	0.436124837	0.514632075

Residential (Deep Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.752248092
R Square	0.565877192
Adjusted R Square	0.5634383
Standard Error	105.7520673
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2594820.496	2594820.496	232.0222255	4.42027E-34
Residual	178	1990662.952	11183.49973		
Total	179	4585483.448			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	248.7081064	15.29965652	16.25579673	5.11914E-37	218.5160572	278.9001555	218.5160572	278.9001555
WH-HDD	0.363829131	0.023885409	15.23227578	4.42027E-34	0.316694123	0.410964139	0.316694123	0.410964139

Residential (Lower Post BC)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.81614908
R Square	0.666099321
Adjusted R Square	0.664223475
Standard Error	102.4652481
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3728162.932	3728162.932	355.0926572	2.91803E-44
Residual	178	1868844.62	10499.12708		
Total	179	5597007.552			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	482.5359337	13.76104774	35.06534841	7.55861E-82	455.3801456	509.6917217	455.3801456	509.6917217
WL-HDD	0.350883145	0.018620514	18.84390239	2.91803E-44	0.31413778	0.387628511	0.31413778	0.387628511

Residential (Upper Liard)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.837904563
R Square	0.702084057
Adjusted R Square	0.700410372
Standard Error	81.41823385
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2780729.358	2780729.358	419.483968	1.11237E-48
Residual	178	1179949.327	6628.928803		
Total	179	3960678.685			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	434.4074757	10.93444093	39.72836641	2.07109E-90	412.8296594	455.9852921	412.8296594	455.9852921
WL-HDD	0.303036141	0.014795742	20.48130777	1.11237E-48	0.273838507	0.332233774	0.273838507	0.332233774

Residential (Watson Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91758524
R Square	0.841962672
Adjusted R Square	0.841074822
Standard Error	62.27248406
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3677439.547	3677439.547	948.3161829	3.18151E-73
Residual	178	690259.4843	3877.862272		
Total	179	4367699.032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	515.255402	8.36317329	61.61003535	5.5467E-122	498.7516761	531.759128	498.7516761	531.759128
WL-HDD	0.348488007	0.011316477	30.79474278	3.18151E-73	0.326156287	0.370819726	0.326156287	0.370819726

Residential (Keno City)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.45197141
R Square	0.204278155
Adjusted R Square	0.199807808
Standard Error	98.54936507
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	443801.0337	443801.0337	45.69625911	1.90467E-10
Residual	178	1728731.969	9711.977356		
Total	179	2172533.003			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	195.761055	14.2576072	13.73028813	1.00194E-29	167.625366	223.8967439	167.625366	223.8967439
WH-HDD	0.150465857	0.022258589	6.759900821	1.90467E-10	0.106541183	0.194390532	0.106541183	0.194390532

Residential (Stewart Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.578269149
R Square	0.334395209
Adjusted R Square	0.330655856
Standard Error	179.1744974
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2870886.34	2870886.34	89.4259596	1.88615E-17
Residual	178	5714423.091	32103.50051		
Total	179	8585309.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	462.7767125	24.06307365	19.23182047	2.54602E-45	415.2911039	510.2623212	415.2911039	510.2623212
WL-HDD	0.307909483	0.032560515	9.456529998	1.88615E-17	0.243655187	0.372163779	0.243655187	0.372163779

Residential (Swift River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.478815384
R Square	0.229264172
Adjusted R Square	0.224934195
Standard Error	309.1635718
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5060894.424	5060894.424	52.9481323	1.05385E-11
Residual	178	17013616.31	95582.11413		
Total	179	22074510.74			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	774.2960938	44.72817013	17.3111507	5.25351E-40	686.0303795	862.5618081	686.0303795	862.5618081
WH-HDD	0.508109656	0.069828406	7.276546729	1.05385E-11	0.370311618	0.645907694	0.370311618	0.645907694

WL-YECL-12

Reference: Pension Expense, Section 5, Page 5-3

YECL does not provide a forecast of pension expenses and is also proposing to use a deferral account to flow through increases or decreases to required cash contributions to the company's defined benefit pension plan as a result of the required annual actuarial evaluations.

Request:

Please explain, in much more detail than is provided in the application, the functioning of the pension plans. More specifically:

(a) How were the amounts of the Defined Benefit payments for 2010 to 2012 calculated?

(b) What is the reason and purpose for the DB Special Payments for 2010 to 2012? How were these amounts calculated?

(c) On what basis is YECL assuming that the 2013 DB contribution rates will be the same as 2012?

(d) The application states that the next actuarial evaluation to determine the 2013 DB funding requirements was to be completed as of Dec. 31, 2013. Should this have been Dec. 31st, 2013? If no, then please describe the outcome of that evaluation.

(e) Is the purpose of the proposed deferral account to handle what was in 2010 to 2012 the DB Special Payments? Please explain the purpose and functioning of the proposed deferral account in more detail.

(f) Please provide schedules showing the actual and forecast payments to the defined benefit and defined contribution plans for the period from 2008 to 2015, both in percent of payroll and actual amounts. Please explain any significant variations in these costs. Please explain why the company's contribution to the defined contribution plan is 6% and explain if that amount could change during the test years.

(g) Please provide a schedule showing the actual and forecast OPEB costs for the period from 2008 to 2015, both in percent of payroll and actual amounts. Please explain any significant variations in these costs.

Response:

(a) The Defined Benefit payments for 2010 and 2011 were calculated based on the actuarial valuation prepared as at December 31, 2009. The actuarial valuation determined a % of pensionable salary to be funded based on the total funding required divided by the forecast pensionable salary for the year. The % was then applied to the actual pensionable salary to determine the actual cash payments.

The Defined Benefit payment for 2012 was based on the actuarial valuation prepared as at December 31, 2012. The actuarial valuation determined the total funding required and this was the amount paid.

(b) The DB Special Payments are required to fund the unfunded liability in the plan. Where the defined benefit portion of the plan has an unfunded liability, the employer must contribute, on at least a monthly basis (or as a lump sum if desired), special payments sufficient to amortize the unfunded liability over a period not exceeding 15 years from the date the unfunded liability was established.

These amounts were calculated by Mercer (Canada) Limited, the preparer of the actuarial valuations for the period.

(c) Yukon Electrical is not expecting the 2013 DB contribution rates will be the same as 2012. At the time the filing was prepared, the valuation as at December 31, 2012, which determines the 2013 funding, had not yet been completed. As a result, Yukon Electrical had no better information with which to forecast the 2013 DB contributions than the 2012 actual funding.

(d) An actual valuation as of December 31, 2012, which is used to determine 2013 funding requirements, was completed in July 2013 (please refer to YUB-YECL-5(a) Attachment 1). As a result of the valuation, Yukon Electrical's required DB pension funding for 2013 is as follows:

Current service	$605,000
Special payment	$351,000
Total	$956,000

(e) Beginning in 2013, the purpose of the proposed deferral account is to flow through all non-capitalized increases or decreases to required cash contributions to the defined benefit pension plan. This includes both the current service and special payment portions of the contributions.

(f) Please refer to WL-YECL-12(f) Attachment 1 for a schedule showing the actual and forecast payments to the defined benefit and defined contribution plans for the period from 2008 to 2015.

DB pension contributions are determined based on actuarial valuations. These valuations are impacted by many factors including the performance of the investments held by the pension plan, inflation rates, and changes in actuarial assumptions including mortality rates. As a result, DB contributions will fluctuate from year to year.

The company's contribution to the defined contribution plan is 6% and it is reviewed annually by management as part of its review of the compensation package offered by the company. No changes are forecast to the employer contribution rate of 6% for the test period.

(g) The actual and forecast OPEB costs for the period from 2008 to 2015 are as follows:

Year	GRA Forecast	Actual
2008 Actual	60	37
2009 Actual	60	24
2010 Actual	N/A	20
2011 Actual	N/A	11
2012 Actual	N/A	37
2013 Forecast	37	N/A
2014 Forecast	37	N/A
2015 Forecast	37	N/A

Since 2008, Yukon Electrical has accounted for OPEB on the cash basis, which means that the actual cash outlay is expensed. The cash outlay is based on the claims made by retirees for their health and dental care in each year and is not impacted by the total current payroll expenses. Therefore, the percentage of payroll is not applicable and was not calculated. The forecast is based on past experience as well as growth in the number as well as age of retirees.

The Yukon Electrical Company Limited
Actual and Forecast Pension Payments 2008-2015

	Current Service Payments	Special Payments	Total DB Payments	DB Pensionable Salary	Payments as % of DB Salary	Defined Contribution Payments	DC Pensionable Salary	Payments as % of DB Salary
2008 Forecast	487	93	580	2,148	27.00%	(1)	(1)	(1)
2009 Forecast	517	98	615	2,278	27.00%	(1)	(1)	(1)
2008 Actual	521	99	620	2,296	27.00%	(1)	(1)	(1)
2009 Actual	566	86	652	2,415	27.00%	(1)	(1)	(1)
2010 Actual	509	284	793	2,141	37.04%	121	2,017	6.00%
2011 Actual	543	303	846	2,284	37.04%	162	2,700	6.00%
2012 Actual	630	638	1,268	(2)	(2)	166	2,767	6.00%
2013 Forecast	630	638	1,268	(2)	(2)	172	2,867	6.00%
2014 Forecast	630	638	1,268	(2)	(2)	178	2,967	6.00%
2015 Forecast	630	638	1,268	(2)	(2)	184	3,067	6.00%

(1) Yukon Electrical employees are part of two different pension plans sponsored by Canadian Utilities Ltd. - Plan 1 (DC) and Plan 2 (DB). Plan 1 was considered fully funded until 2010 and, as a result, no contributions to the DC plan were required for 2008 and 2009.

(2) Prior to 2012, the pension valuation determined a % funding requirement for both current service and special payments based on the required funding amount divided by a forecast of pensionable salary. Actual cash contributions were calculated based on the calculated % multiplied by the actual pensionable salary. As result, each year there was a slight difference between the required funding and the actual payments made.

Beginning in 2012, the method for calculating the actual cash payments changed. The actuarial valuation calculates the required funding amount and the actual payments are made to exactly equal to this amount. As a result, the funding is no longer based on a % of pensionable salary so it was not calculated for 2012-2015.

WL-YECL-16

Reference: Return on Equity, Section 8, Page 8-6

YECL is seeking approval for a deferral account that would flow through any change in its ROE according to the BCUC Automatic Adjustment Mechanism, which will become operative if a long term Canada bond yield of 3.8% is met or exceeded.

Request:

(a) Please describe the rationale for and functioning of the AAM. How is the change in the ROE linked to the magnitude of the change in bond yields? Please explain the linkage to a long term Canada bond yield of 3.8% for activating the AAM. Is there a cap on the frequency and magnitude of the AAM changing the ROE to prevent numerous and excessive increases in the ROE?

(b) Using YECL's 2015 forecast long term bond rate range of 4.0% to 4.4%, what would be the range of adjustments to YECL's ROE through the AAM? What would be the revenue range collected through the proposed deferral account and the impact in a $/kwh and rate percent increase basis for the different customer classes?

(c) Is the AAM reversible? For example, if the bond rate dropped to or below some threshold, would the AAM decrease YECL's approved ROE? If yes, what is that lower bond yield threshold? If no, please explain why not? Why it is fair and reasonable for the AAM to be able to increase the ROE but not decrease it?

Response:

(a) As per page 88 of the May 10, 2013 BCUC GCOC Decision, the rationale for the AAM is provided below:

> …the application of the AAM has the potential to contribute to regulatory efficiency. Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the

standard than taking no consideration of changes in the market over a three year period as suggested by FBCU.

Fifty percent of the change in the Long Canada Bond Forecast will be reflected in the change to the ROE.

Page 91 of the May 10, 2013 BCUC GCOC Decision discussed the long Canada bond yield floor of 3.8%. The excerpt is provided below.

> With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.

With respect to frequency, the AAM is expected to be applied annually. The BCUC GCOC Decision does not prescribe any magnitude restrictions.

(b) The basic adjustment formula provided on Page 90 of the May 10, 2013 BCUC GCOC Decision regarding the Generic Cost of Capital Proceeding is as follows:

> ROE_1 = Base ROE (8.75%) + 0.50 x ($LCBF_t$ – BaseLCBF) + 0.50 x ($UtilBondSpread_t$ – BaseUtilBondSpread)
>
> Where:
>
> $LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.
>
> $UtilBondSpread_t$ is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

Based on Yukon Electrical's forecast long term bond rate range of 4.0% to 4.4%, and assuming that there is no change in the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields, the range of adjustments to Yukon Electrical's ROE through the AAM would be 0.1% to 0.3% (ROE of 9.31% to 9.51%).

In the case of a 0.1% increase to the ROE, additional revenue collected through the AAM would be $54,000 for 2014 and $60,000 for 2015. Please refer to WL-YECL-16(b) Attachment 1 for the calculation. The impact would be a $0.0001/kWh and the cumulative rate increase over existing rates for all customer classes would be 9.6% through to 2014 (9.5% in the Application) and 11.8% through to 2015 (11.7% in the Application).

In the case of a 0.3% increase to the ROE, additional revenue collected through the proposed deferral account would be $161,000 for 2014 and $181,000 for 2015. Please refer to WL-YECL-16(b) Attachment 1 for the calculation. The impact would be $0.0004/kWh and the cumulative rate increase over existing rates for all customer classes through to 2014 would be 9.8% (9.5% in the Application) and 12.0% for 2015 (11.7% in the Application).

(c) As noted above, the BCUC determined that any change in the ROE resulting from the AAM formula is subject to an actual long Canada bond yield of

3.8% being met or exceeded so as to deal with downward bias in the AAM formula. Provided this condition is met, the change in the ROE determined by the AAM formula may be positive or negative depending on the combined change in the Long Canada Bond Forecast and Utility Bond Spreads.

The Yukon Electrical Company Limited
Impact of the AAM on ROE and Revenue Requirement

Impact on Revenue Requirement of 0.1% Increase in Return on Equity

	Source	2014	2015	
Mid Year Rate Base ($000s)	Schedule 8.1 of Application	86,063	96,812	(a)
Common Stock Ratio	Schedule 8.1 of Application	43.66%	43.70%	(b)
Change in ROE Due to AAM		0.1%	0.1%	(c)
Tax Rate	Schedule 10.1 of Application	30%	30%	(d)
Change in Revenue Requirement ($000s)		**54**	**60**	**(a) x (b) x (c) / (1-(d))**

Impact on Revenue Requirement of 0.3% Increase in Return on Equity

	Source	2014	2015	
Mid Year Rate Base ($000s)	Schedule 8.1 of Application	86,063	96,812	(a)
Common Stock Ratio	Schedule 8.1 of Application	43.66%	43.70%	(b)
Change in ROE Due to AAM		0.3%	0.3%	(c)
Tax Rate	Schedule 10.1 of Application	30%	30%	(d)
Change in Revenue Requirement ($000s)		**161**	**181**	**(a) x (b) x (c) / (1-(d))**

WL-YECL-17

Reference: Common Equity Ratio, Section 8, Page 8-4 and 8-6

YECL refers to its expert evidence from its previous GRA which stated that YECL's business risk is similar to NUL(YK). In the time since, NUL(YK)'s common equity ratio has increased from 40% to 43.5%.

In the previous GRA, the YUB approved a common equity ratio of 40%. In the time since the BCUC has increased its benchmark common equity ratio from 35.01% to 38%.

Request:

(a) With the NUL(YK) and the BCUC common equity ratios both having been increased by 3.5%, please explain why YECL is seeking a common equity ratio of 44% rather than the 43.5% that would be in keeping with the 3.5% increases in the NWT and BC.

(b) Please provide a calculation of YECL's coverage ratios including before and after tax interest coverage ratios, funds from operations to interest coverage ratios, funds from operations to debt ratios, for the 2008 and 2009 GRA forecasts and actuals, the 2010 to 2012 actuals as well as for the 2013 to 2015 GRA forecasts.

Response:

(a) Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(b) Please refer to WL-YECL-17(b) Attachment 1for the ratio calculations.

Yukon Electrical notes the results are consistent with the ratios calculated in NWTPUB Decision 24-2008 and Decision 25-2008 when the NWT Board approved common equity ratios of 43.5% and 44% for Northland (Yellowknife) and Northland (NWT), respectively. The ratios calculated by the Board in Table 3 of the above noted decisions were as follows:

	2008	2009	2010
Northland (Yellowknife)			
Decision 24-2008			
Interest Coverage	2.38	2.55	2.51
FFO interest Coverage	4.0	4.2	4.2
Northland (NWT)			
Decision 24-2008			
Interest Coverage	2.53	3.35	3.29
FFO interest Coverage	4.5	5.6	5.6

The Yukon Electrical Company Limited
Credit Metrics 2008-2009 GRA

2008 GRA Approved

	2008 GRA Approved				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	26,621	59.11%	6.87%	4.06%	4.06%
Common Stock Equity	17,747	39.41%	9.08%	3.58%	5.46%
No Cost Capital	669	1.49%	0.00%	0.00%	0.00%
	45,037	100.00%		7.64%	9.52%
Net Rate Base (excl WIP)	46,090				
Depreciation	2,391				
Interest Coverage Ratio					2.35
FFO/Debt				15%	
FFO Interest Coverage				3.23	
Debt/Capital				59%	

2009 GRA Approved

	2009 GRA Approved				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	29,730	59.17%	6.60%	3.91%	3.91%
Common Stock Equity	19,820	39.45%	8.92%	3.52%	5.33%
No Cost Capital	695	1.38%	0.00%	0.00%	0.00%
	50,245	100.00%		7.43%	9.24%
Net Rate Base (excl WIP)	49,478				
Depreciation	2,633				
Interest Coverage Ratio					2.36
FFO/Debt				15%	
FFO Interest Coverage				3.21	
Debt/Capital				59%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2008 Actual

	2008 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	24,575	56.81%	6.97%	3.96%	3.96%
Common Stock Equity	17,994	41.59%	7.03%	2.93%	4.47%
No Cost Capital	693	1.60%	0.00%	0.00%	0.00%
	43,262	100.00%		6.88%	8.42%
Net Rate Base (excl WIP)	45,946				
Depreciation	2,201				
Interest Coverage Ratio					2.13
FFO/Debt				14%	
FFO Interest Coverage				3.13	
Debt/Capital				57%	

2009 Actual

	2009 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	27,650	57.34%	6.73%	3.86%	3.86%
Common Stock Equity	19,866	41.20%	11.35%	4.67%	7.08%
No Cost Capital	702	1.45%	0.00%	0.00%	0.00%
	48,217	100.00%		8.53%	10.94%
Net Rate Base (excl WIP)	49,116				
Depreciation	2,313				
Interest Coverage Ratio					2.84
FFO/Debt				17%	
FFO Interest Coverage				3.50	
Debt/Capital				57%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2010 Actual

	2010 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	29,950	57.27%	6.58%	3.77%	3.77%
Common Stock Equity	21,682	41.46%	10.54%	4.37%	6.52%
No Cost Capital	666	1.27%	0.00%	0.00%	0.00%
	52,298	100.00%		8.14%	10.29%
Net Rate Base (excl WIP)	50,026				
Depreciation	2,462				
Interest Coverage Ratio					2.73
FFO/Debt				16%	
FFO Interest Coverage				3.32	
Debt/Capital				57%	

2011 Actual

	2011 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	32,450	57.36%	6.42%	3.68%	3.68%
Common Stock Equity	23,472	41.49%	10.74%	4.46%	6.51%
No Cost Capital	649	1.15%	0.00%	0.00%	0.00%
	56,571	100.00%		8.14%	10.19%
Net Rate Base (excl WIP)	52,408				
Depreciation	2,840				
Interest Coverage Ratio					2.77
FFO/Debt				16%	
FFO Interest Coverage				3.41	
Debt/Capital				57%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2012 Actual

	2012 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	36,950	58.35%	6.16%	3.59%	3.59%
Common Stock Equity	25,740	40.65%	10.18%	4.14%	5.91%
No Cost Capital	631	1.00%	0.00%	0.00%	0.00%
	63,321	100.00%		7.73%	9.51%
Net Rate Base (excl WIP)	60,033				
Depreciation	2,821				
Interest Coverage Ratio					2.64
FFO/Debt				14%	
FFO Interest Coverage				3.28	
Debt/Capital				58%	

The Yukon Electrical Company Limited
Credit Metrics 2013-2015 Forecast

2013 Test Period

	2013 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	40,150	55.52%	5.99%	3.32%	3.32%
Common Stock Equity	31,540	43.61%	9.21%	4.01%	5.74%
No Cost Capital	632	0.87%	0.00%	0.00%	0.00%
	72,322	100.00%		7.34%	9.06%
Net Rate Base (excl WIP)	72,329				
Depreciation	5,126				
Interest Coverage Ratio					2.73
FFO/Debt				20%	
FFO Interest Coverage				4.34	
Debt/Capital				56%	

2014 Test Period

	2014 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	47,950	55.58%	5.84%	3.25%	3.25%
Common Stock Equity	37,670	43.66%	9.21%	4.02%	5.75%
No Cost Capital	651	0.75%	0.00%	0.00%	0.00%
	86,271	100.00%		7.27%	8.99%
Net Rate Base (excl WIP)	86,063				
Depreciation	5,952				
Interest Coverage Ratio					2.77
FFO/Debt				20%	
FFO Interest Coverage				4.36	
Debt/Capital				56%	

The Yukon Electrical Company Limited
Credit Metrics 2013-2015 Forecast

2015 Test Period

	2015 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	54,550	55.62%	5.77%	3.21%	3.21%
Common Stock Equity	42,860	43.70%	9.21%	4.03%	5.75%
No Cost Capital	670	0.68%	0.00%	0.00%	0.00%
	98,080	100.00%		7.23%	8.96%
Net Rate Base (excl WIP)	96,812				
Depreciation	6,820				
Interest Coverage Ratio					2.79
FFO/Debt				20%	
FFO Interest Coverage				4.39	
Debt/Capital				56%	

WL-YECL-18

Reference: Long Term Debt, Section 8, Page 8-7

During the 2013-15 test period, YECL is forecasting that it will issue long term debt all 3 years. The recommended rates of 4.30%, 5.00% and 5.75% are based on the best information available at the time the forecast was prepared.

Request:

(a) Please confirm that debt issues for YECL as well as its parent ATCO Electric are raised by Canadian Utilities Limited.

(b) Please provide the bond yields for a benchmark 30 year CU Ltd. bond, by month, for the 12 months ended June 2013, the corresponding 30-year long Canada bond yields and the resulting yield spreads.

(c) Please provide updated forecasts of 10 year and 30 year long Canada bond yields for each of the years 2013, 2014 and 2015. Please rationalize any changes in the forecast long Canada bond yields from current levels.

Response:

(a) Not confirmed. Debt issues for Yukon Electrical as well as its parent, ATCO Electric, are raised by CU Inc. The forecast all-in rates included in Yukon Electrical's application are 4.35%, 5.05% and 5.80% for the years 2013, 2014 and 2015, respectively.

(b) The below data relates to the 4.543% 30 year debenture issued by CU Inc. on October 24, 2011. This debenture was issued at an actual credit spread of 160 basis points. Included in the table, by month from June 2012 to June 2013, is the indicative debenture yield, the 30 year Long Canada bond yield, and the indicative credit spread of the debentures (calculated as the indicative debenture yield less the Long Canada yield).

	30-year Long Canada	CU Inc. 4.543% bond due Oct 2041	
Date	Yield (%)	Yield (%)	Spread (bps)
29-Jun-12	2.33	3.90	157
31-Jul-12	2.27	3.78	151
31-Aug-12	2.34	3.81	147
28-Sep-12	2.32	3.71	139
31-Oct-12	2.38	3.85	147
30-Nov-12	2.30	3.77	147
31-Dec-12	2.37	3.80	143
31-Jan-13	2.57	3.97	140
28-Feb-13	2.52	3.93	141
28-Mar-13	2.50	3.90	140
30-Apr-13	2.37	3.81	144
31-May-13	2.63	3.95	132
28-Jun-13	2.90	4.36	146

(c) Updated forecast long term debt rates are as follows:

	2013	2014	2015
LONG CANADA BOND RATE	3.00% - 3.20%	3.20% - 3.90%	4.00% - 4.40%
CREDIT SPREAD	1.45% – 1.65%	1.45% – 1.65%	1.45% – 1.65%
DEBENTURE RATE RANGE	4.45% – 4.85%	4.65% – 5.55%	5.45% - 6.05%
DEBENTURE RATE	4.65%	5.10%	5.75%
ISSUE COSTS	0.05%	0.05%	0.05%
RECOMMENDED ALL-IN RATE	4.70%	5.15%	5.80%

The forecast all-in rates for 2013 and 2014 have increased due to the significant increase in the underlying Long Canada Bond Rate observed over the past several weeks.

Please refer to WL-YECL-18(c) Attachments 1 through 4 for supporting forecast data from BMO Capital Markets, TD Economics, RBC Economics and Consensus Forecasts.

Interest Rate Forecasts
Percent (averages)

	Actual Jun	2013 Jul	Aug	Sep	2013 Q4	2014 Q1	Q2	Q3	Q4
Cdn. Yield Curve									
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50
3 month	1.02	1.03	1.03	1.03	1.03	1.03	1.03	1.28	1.53
6 month	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.30	1.55
1 year	1.11	1.12	1.15	1.18	1.25	1.36	1.50	1.75	2.05
2 year	1.15	1.19	1.26	1.32	1.45	1.65	1.95	2.25	2.50
3 year	1.26	1.30	1.39	1.46	1.60	1.85	2.15	2.45	2.70
5 year	1.63	1.75	1.85	1.90	2.00	2.20	2.45	2.75	3.00
7 year	1.95	2.10	2.15	2.20	2.35	2.55	2.80	3.05	3.25
10 year	2.24	2.40	2.50	2.55	2.70	2.90	3.10	3.30	3.55
30 year	2.76	2.85	2.95	3.00	3.10	3.30	3.50	3.70	3.90
1m BA	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.38	1.61
3m BA	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.42	1.66
6m BA	1.34	1.40	1.40	1.40	1.40	1.40	1.40	1.65	1.90
12m BA	1.45	1.50	1.55	1.55	1.65	1.75	1.90	2.15	2.40
Prime Rate	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.25	3.50
U.S. Yield Curve									
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
3 month	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
6 month	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
1 year	0.14	0.14	0.14	0.14	0.14	0.14	0.19	0.31	0.46
2 year	0.33	0.36	0.36	0.36	0.36	0.36	0.46	0.70	1.00
3 year	0.58	0.67	0.68	0.69	0.71	0.72	0.85	1.05	1.40
5 year	1.20	1.42	1.45	1.48	1.55	1.55	1.60	1.80	2.05
7 year	1.71	1.97	2.02	2.07	2.16	2.17	2.20	2.40	2.60
10 year	2.30	2.50	2.60	2.65	2.80	2.95	3.10	3.30	3.45
30 year	3.40	3.49	3.56	3.60	3.75	3.90	4.05	4.15	4.30
1m LIBOR	0.19	0.20	0.20	0.20	0.20	0.20	0.25	0.25	0.25
3m LIBOR	0.27	0.25	0.30	0.30	0.30	0.35	0.35	0.40	0.40
6m LIBOR	0.41	0.40	0.40	0.45	0.45	0.50	0.50	0.55	0.55
12m LIBOR	0.68	0.70	0.70	0.70	0.75	0.75	0.85	1.00	1.15
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Other G7 Yields									
ECB Refi	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
10yr Bund	1.60	1.65	1.75	1.85	2.00	2.25	2.50	2.70	2.95
BoE Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
10yr Gilt	2.31	2.35	2.45	2.50	2.65	2.90	3.05	3.25	3.45
BoJ O/N	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
10yr JGB	0.85	0.85	0.85	0.85	0.90	0.95	1.05	1.15	1.20



INTEREST RATE OUTLOOK

	Spot Rate	2012				2013				2014			
	Jul-11	Q1	Q2	Q3	Q4	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA													
Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50
3-mth T-Bill Rate	1.02	0.91	0.87	0.97	0.92	0.98	1.02	0.95	0.95	0.95	0.95	1.05	1.40
2-yr Govt. Bond Yield	1.13	1.20	1.03	1.07	1.14	1.00	1.22	1.20	1.25	1.30	1.35	1.55	1.70
5-yr Govt. Bond Yield	1.76	1.57	1.25	1.30	1.38	1.30	1.80	1.75	1.90	2.00	2.10	2.20	2.35
10-yr Govt. Bond Yield	2.45	2.11	1.74	1.73	1.80	1.76	2.44	2.45	2.55	2.70	2.75	2.80	2.85
30-yr Govt. Bond Yield	2.93	2.66	2.33	2.32	2.36	2.50	2.89	2.95	3.05	3.10	3.15	3.20	3.25
10-yr-2-yr Govt Spread	1.33	0.91	0.71	0.66	0.66	0.76	1.22	1.25	1.30	1.40	1.40	1.25	1.15
U.S.													
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-mth T-Bill Rate	0.04	0.07	0.09	0.10	0.05	0.07	0.04	0.10	0.20	0.20	0.20	0.20	0.20
2-yr Govt. Bond Yield	0.34	0.33	0.33	0.23	0.25	0.25	0.36	0.30	0.40	0.45	0.55	0.75	0.90
5-yr Govt. Bond Yield	1.41	1.04	0.72	0.62	0.72	0.77	1.41	1.25	1.40	1.50	1.60	1.75	1.90
10-yr Govt. Bond Yield	2.59	2.23	1.67	1.65	1.78	1.87	2.52	2.45	2.60	2.75	2.85	2.95	3.05
30-yr Govt. Bond Yield	3.63	3.35	2.76	2.82	2.95	3.10	3.52	3.65	3.75	3.90	4.00	4.00	4.05
10-yr-2-yr Govt Spread	2.25	1.90	1.34	1.42	1.53	1.62	2.16	2.15	2.20	2.30	2.30	2.20	2.15
CANADA - U.S SPREADS													
Can - U.S. T-Bill Spread	0.99	0.84	0.78	0.87	0.87	0.91	0.98	0.85	0.75	0.75	0.75	0.85	1.20
Can - U.S. 10-Year Bond Spread	-0.13	-0.12	0.07	0.08	0.02	-0.11	-0.08	0.00	-0.05	-0.05	-0.10	-0.15	-0.20

F: Forecast by TD Bank Group as at July 2013; All forecasts are end-of-period; Source: Bloomberg, Bank of Canada, Federal Reserve.

GLOBAL STOCK MARKETS

	Jul-11	30-Day % Chg.	YTD % Chg.	52-Week High	52-Week Low
S&P 500	1,653	1.6	15.9	1,669	1,335
S&P/TSX Composite	12,307	0.7	-1.0	12,879	11,425
DAX	8,150	-0.9	7.1	8,531	6,390
FTSE 100	6,537	3.1	10.8	6,840	5,498
Nikkei	14,473	8.7	39.2	15,627	8,366
MSCI AC World Index*	364	0.1	7.0	380	303

* Is a weighted equity index including both developed and emerging markets
Source: Bloomberg.

COMMODITY PRICE FORECASTS

	Price	52-Week	52-Week	2012				2013F				2014F				Annual Average		
	Jul-11	High	Low	Q1	Q2	Q3	Q4	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	2012	2013F	2014F
Crude Oil (WTI, $US/bbl)	107	107	84	103	93	92	88	94	94	93	95	95	92	95	95	94	94	94
Natural Gas ($US/MMBtu)	3.69	4.38	2.63	2.45	2.28	2.88	3.40	3.50	4.01	3.85	4.05	3.90	4.00	3.90	4.25	2.75	3.85	4.01
Gold ($US/troy oz.)	1286	1790	1201	1690	1612	1655	1717	1632	1418	1275	1200	1175	1150	1175	1250	1668	1381	1188
Silver (US$/troy oz.)	20.1	35.0	18.5	32.6	29.5	30.0	32.6	30.1	23.3	19.6	17.9	17.8	17.0	18.0	19.3	31.17	22.71	18.00
Copper (cents/lb)	309	379	301	376	357	350	359	360	325	318	335	330	325	320	310	361	335	321
Nickel (US$/lb)	6.19	8.50	6.04	8.91	7.77	7.42	7.70	7.85	6.80	7.50	8.00	8.00	8.60	8.50	8.20	7.95	7.54	8.33
Aluminum (Cents/lb)	82	100	80	99	90	87	91	91	83	90	96	96	96	100	100	92	90	98
Wheat ($US/bu)	8.86	10.89	8.77	9.54	9.36	9.90	10.05	9.32	9.14	9.25	9.30	9.35	9.25	9.00	8.75	9.71	9.25	9.09

F: Forecast by TD Bank Group as at July 2013; All forecasts are period averages; Source: Bloomberg, USDA (Haver).

Interest rate outlook

%, end of period

	Actuals						Forecast					
	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4
Canada												
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50
Three-month	0.92	0.88	0.90	1.05	0.98	1.02	1.00	1.00	1.05	1.10	1.25	1.55
Two-year	1.20	1.03	1.15	1.05	1.00	1.22	1.15	1.20	1.30	1.55	1.80	2.00
Five-year	1.56	1.25	1.35	1.30	1.30	1.80	1.85	1.95	2.10	2.25	2.45	2.55
10-year	2.11	1.74	1.75	1.75	1.88	2.44	2.50	2.70	2.90	3.15	3.30	3.40
30-year	2.64	2.33	2.40	2.40	2.50	2.90	3.00	3.20	3.40	3.55	3.65	3.75
United States												
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Three-month	0.07	0.09	0.10	0.09	0.07	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Two-year	0.34	0.25	0.25	0.25	0.25	0.36	0.35	0.55	0.65	0.85	1.20	1.60
Five-year	1.04	0.70	0.72	0.70	0.77	1.41	1.45	1.75	1.90	2.10	2.30	2.50
10-year	2.20	1.60	1.65	1.70	1.87	2.52	2.60	2.85	3.05	3.30	3.45	3.60
30-year	3.32	2.70	2.80	2.90	3.10	3.52	3.70	3.90	4.10	4.20	4.30	4.35
United Kingdom												
Bank rate	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Two-year	0.43	0.40	0.20	0.20	0.21	0.41	0.30	0.40	0.50	0.60	0.70	0.70
10-year	2.00	1.80	1.70	1.70	1.78	2.46	2.50	2.65	2.75	2.85	2.90	3.00
Eurozone												
Refi rate	1.00	1.00	0.75	0.75	0.75	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Two-year	0.09	0.10	0.00	0.00	-0.02	0.20	0.15	0.20	0.30	0.30	0.35	0.40
10-year	1.61	1.50	1.50	1.50	1.29	1.73	1.70	1.85	2.00	2.10	2.15	2.25
Australia												
Cash target rate	4.25	3.50	3.50	3.00	3.00	2.75	2.50	2.25	2.25	2.25	2.25	2.25
Two-year	3.49	2.46	2.49	2.75	2.83	2.58	2.40	2.40	2.50	2.50	2.60	2.70
10-year	4.10	3.04	2.94	3.00	3.42	3.76	3.70	3.75	3.95	4.10	4.35	4.50
New Zealand												
Cash target rate	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.75	3.00	3.00	3.25
Two-year swap	3.11	2.37	2.55	2.60	2.85	2.85	3.10	3.20	3.30	3.40	3.40	3.50
10-year swap	4.17	3.40	3.57	3.80	3.96	4.16	4.50	4.60	4.60	4.60	4.90	5.30
Yield curve												
Canada	91	71	60	70	88	122	135	150	160	160	150	140
United States	186	135	140	145	162	216	225	230	240	245	225	200
United Kingdom	157	140	150	150	157	205	220	225	225	225	220	230
Eurozone	152	140	150	150	131	153	155	165	170	180	180	185
Australia	61	58	45	25	59	118	130	135	145	160	175	180
New Zealand	106	103	102	120	111	131	140	140	130	120	150	180

* Two-year/10-year spread in basis points

Source: Reuters, RBC Economics Research

Central bank policy rate

%, end of period

		Current	Last	
United States	Fed funds	0.0-0.25	1.00	Dec. 16, 2008
Canada	Overnight rate	1.00	0.75	Sep. 8, 2010
United Kingdom	Bank rate	0.50	1.00	Mar. 5, 2009

		Current	Last	
Eurozone	Refi rate	0.50	0.75	May 2, 2013
Australia	Cash rate	2.75	3.00	May 8, 2013
New Zealand	Cash rate	2.50	3.00	Mar. 10, 2011

Source: Bloomberg, Reuters, RBC Economics Research

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date			
						1.0%		2.5%	
Unemploy-ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2013	2014	2013	2014	FY 13-14	FY 14-15	End Oct'13	End Jul'14	End Oct'13	End Jul'14
7.1	6.9	-49.0	-42.0	na	na	na	na	na	na
7.0	6.7	-48.2	-39.6	na	na	1.0	1.2	2.6	3.2
7.1	6.9	-50.1	-33.0	-17.0	-6.0	1.0	1.1	2.4	2.5
7.1	7.0	-52.4	-42.4	na	na	1.0	1.0	na	na
7.1	7.0	-54.0	-50.0	-11.0	-5.0	1.0	1.2	1.9	2.2
7.0	6.7	-57.0	-48.0	-18.0	-11.0	1.0	1.0	2.6	3.0
7.1	7.1	-65.7	-62.5	na	na	na	na	na	na
7.1	7.0	-55.5	-46.0	na	na	1.0	1.0	2.5	2.8
7.1	6.8	-54.5	-53.1	na	na	1.0	1.0	2.5	2.7
7.0	6.8	-54.0	-45.3	-18.0	-8.0	1.0	1.0	2.3	2.9
7.0	6.7	-55.5	-50.5	-19.0	-10.0	1.0	1.3	2.6	3.2
7.1	7.1	-54.7	-46.0	na	na	1.0	1.1	2.5	2.8
na	na	na	na	na	na	na	na	na	na
7.3	8.0	na	na	na	na	1.0	1.0	2.2	2.8
7.1	7.0	-54.2	-46.5	-16.6	-8.0	1.0	1.1	2.4	2.8
7.1	6.9	-53.6	-46.2	-16.1	-9.1				
7.1	7.0	-59.1	-52.1	-16.8	-9.1				
7.3	8.0	-48.2	-33.0	-11.0	-5.0	1.0	1.3	2.6	3.2
7.0	6.7	-65.7	-62.5	-19.0	-11.0	1.0	1.0	1.9	2.2
0.1	0.3	4.5	7.4	3.2	2.5	0.0	0.1	0.2	0.3
7.1	6.9								

International Trade – and Domestic – Headwinds?

Output-based GDP rose by 0.1% (m-o-m) in April after Q1's 0.6% (q-o-q) surge. In y-o-y terms, growth slowed from the 1.7% pace seen in February and March to 1.4% in April. Services led the monthly uptick in GDP, accelerating by 0.3% following a 0.2% rise in March, with wholesale, retail and financial & insurance activity recording gains. By contrast, goods-producing industries had a weak month. Industrial production fell by 0.4% (m-o-m) following a 0.5% rise in March, dragged down by a 1.5% contraction in mining, quarrying, oil & gas extraction over the month. Manufacturing did manage a 0.2% rise following a flat month in March, supported by durables output, but the industrial sector has been impacted by weakness in Canada's major export markets (and more recently by signs of waning domestic demand). US manufacturing has been in the doldrums, although a few leading indicators suggest it could be on the cusp of rebounding (see page 5). This will hopefully give some impetus to Canadian industry which saw manufacturing sales tumbled from a 0.6% (m-o-m) decline in April to -2.4% in May. The 2013 production consensus has faltered this month.

May's trade deficit narrowed to C$-303mn from C$-951mn in April as a 3.2% (m-o-m) fall in imports outpaced the 1.6% drop in exports. A softer job market (June payrolls were mostly unchanged after May's 95,000 surge) is also weighing on domestic demand. On the upside, after a sluggish year, June housing starts recorded a stronger-than-expected 199,586 gain while May's figure was revised from 200,178 to 204,616. Softer housing activity going into 2014 is still expected, and the prospect of a more serious retrenchment could also occur, although the 2013 housing starts outlook has been upgraded.

Canada Overnight Lending Rate – July 8, 2013 = 1.00%

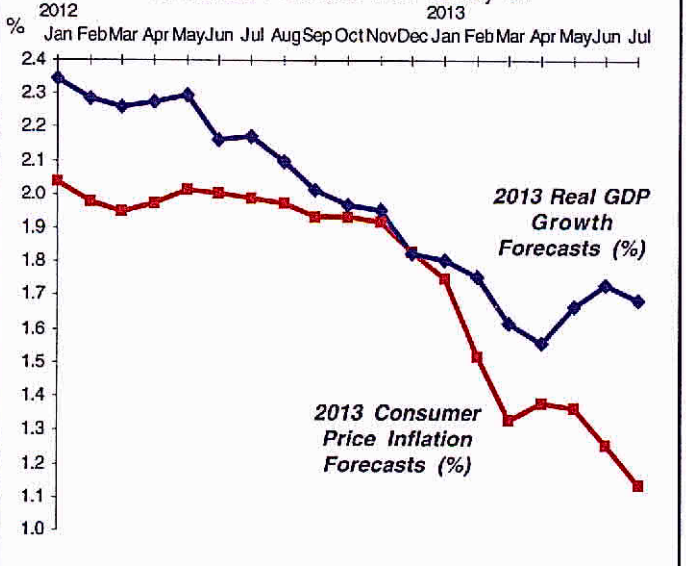
FORECASTS	End Sep. 2013	End Dec. 2013	End Mar. 2014	End June 2014
Consensus Mean Average:	1.00%	1.00%	1.02%	1.03%
Mode (most frequent forecast):	1.00%	1.00%	1.00%	1.00%

Direction of Trade – 2012

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	74.5	United States	50.6
China	4.3	China	11.0
United Kingdom	4.1	Mexico	5.5
EU	*8.5*	*Asia (ex. Japan)*	*14.0*
Asia (ex. Japan)	*6.0*	*EU*	*10.9*
Latin America	*3.0*	*Latin America*	*9.0*

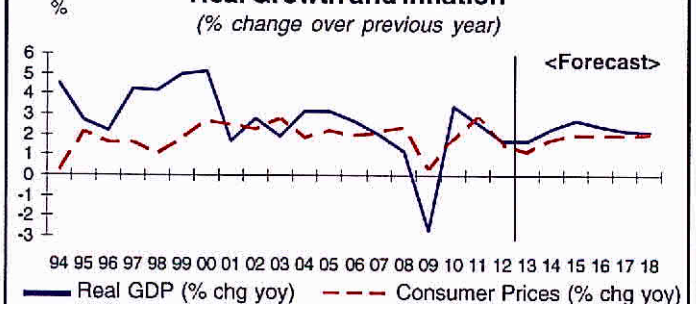
2013 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



Real Growth and Inflation

(% change over previous year)



WL-YECL-19

Reference: RFID, Section 8, Page 8-8

Page 8-8 states that the RFID balance at the end of 2012 was $73,000. Schedule 8-4 shows an RFID balance at the end of 2012 of $69,000.

Request:

What is the correct RFID end of year balance for 2012?

Response:

The correct RFID end of year balance for 2012 is $69,000 as shown on Schedule 8-4.

YCS-YECL-1-3

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain why there are no predicted reductions in energy use for street lighting when technology exists to significantly reduce electricity consumption in street lighting.

Response:

Yukon Electrical has partnered with Yukon Energy in a joint pilot project study to determine the best suited LED streetlight technology for the Yukon. This pilot project is currently testing four different LED lights including the selected brand and model of 43W LED light that ATCO Electric uses. The pilot project study is expected to be completed by the end of 2013.

To date Yukon Electrical has not installed any LED streetlights other than a select few for testing purposes. Yukon Electrical has determined that it is prudent to have thorough testing completed to ensure the LED lights perform to standard light intensities and lighting patterns for the Yukon. Therefore, Yukon Electrical has not incorporated any LED streetlight conversions in the sales forecast. As a result, the wattage and average use per light is constant. Therefore, there are no predicted reductions in energy use for street lighting.

YCS-YECL-1-5

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain how street lighting fits or doesn't fit into the DSM Plan and its overall goal for reducing energy consumption and increasing efficiency for lighting.

Response:

A joint study by Yukon Electrical and Yukon Energy is underway to determine the technology that will be best suited for the Yukon, with a report of the results expected to be delivered by the end of 2013. The results of this technology evaluation work will be utilized separately from the DSM plan to outline a proposed approach for rate design approval by the YUB that addresses the higher capital cost of LED streetlights and the reduced electricity consumption cost.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-7-1

Reference: Demand Side Management Plan

Request:

Please describe all internal DSM projects that the utilities have undertaken or plan to undertake to reduce their overall consumption of electricity in their operations, or to shift their consumption away from peak times.

Response:

Yukon Electrical continues to make internal system efficiency improvements and to address opportunities to improve energy efficiency within its various facilities. Improvements include: the conversion of Hillcrest subdivision to a higher voltage to reduce losses; designing the large transformers at Whistle Bend and at the Shipyard substation to ensure impedances are optimized to reduce internal losses; the current plans for building envelope improvements for the downtown office; insulation upgrades implemented in various plants; and air handling balancing and HVAC replacement in the service complex building. These improvements are outside the scope of the joint DSM plan.

Yukon Energy has completed some additional internal efficiency projects, pilot projects and public education initiatives, these activities along with the joint utility initiatives are outlined in section 5.3.1.5 of Yukon Energy's 2012-2013 General Rate Application and Yukon Energy's IR response YUB-YEC-1-46(d) Attachment 1. These activities are not part of the joint DSM plan. Costs associated with Yukon Energy's activities outside the joint DSM plan are not part of this application.

YCS-YECL-7-2

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain the assumptions that went into this prediction that solar PV would have no penetration until 2025.

Response:

Small-scale solar PV systems do not currently meet the CPR study's economic threshold; however, there is a general expectation that they are likely to become competitive with other electricity generation options sometime within the 20-year period covered by this study. For example, the U.S. Department of Energy's SunShot Initiative is aiming to achieve grid parity by 2020. Recently, a report by Ernst & Young suggested that retail grid parity might generally be achieved between 2012 and 2015. It is difficult to estimate at what point this might occur in the Yukon. On one hand, the installed cost per system will be more expensive than in other areas in Canada and the amount of electricity generated will be lower due to the lower insolation; on the other hand, the cost of electricity generated conventionally is also more expensive. Due to the possibility of PV grid parity during the study period, it was decided to include this technology within the Achievable Potential. During the achievable potential workshops, participants agreed that significant penetration of this technology is not likely to occur until 2025.

YCS-YECL-7-3

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain why considerable generation from solar PV could not happen now to supplement grid power and especially to displace fossil fuels in diesel communities, as opposed to waiting until 2025.

Response:

Yukon Electrical continues to examine renewable electricity generation sources including solar energy and wind energy. In the context of the DSM program, supply side generation was not examined.

YCS-YECL-7-4

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain what incentive programs or technologies were assumed to be in place for that considerable generation by 2025-2030.

Response:

As part of the Customer-side Renewable and Alternative Energy Technologies report, alternative energy incentive programs were not evaluated, only technologies considered. The specific technologies and the analysis of each technology is listed in Appendix G5, sections 5.4-5.9, pages 38-57 of the *Yukon Five Year Demand Side Management Plan* included in the Application.

YCS-YECL-7-5

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please describe how the programs in the DSM Plan will be accessible to customers outside of Whitehorse, and particularly in diesel-powered communities.

Response:

All residential and general service ratepayers will be eligible for programs listed in the joint DSM plan regardless of location in the Yukon.

YCS-YECL-7-6

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please describe what programs exist in the DSM Plan to manage the load, as in to shift the demand from the peaks to the valleys. If there are no programs designed with the intention to shift demand from peaks to valleys, why not?

Response:

All programs included in the DSM Plan have coincidental peak savings, as outlined for each program shown in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management Plan* included in the Application. There are no specific programs to address peak shifting included in the DSM plan. Peak shifting programs tend to be costly and complex to administer as they require a high degree of customer participation and generally require enforceable regulation to ensure the technology is used during those peak times. Under the current rate structure and customer available data, there is no customer incentive to develop programing to address peak shifting. In developing their first DSM programs, the utilities focused on electricity usage savings which is more cost effective and results in coincidental peak savings.

Exhibit 4: Portfolio Results excluding Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - excluding gov. buildings	Lifetime MWh:	0	2,476	6,240	7,132	7,132	22,981	Incentive:	$4	$96	$213	$239	$222	$773	1.1	2.8	2.5	0.9
	Annual MWh:	0	333	1,140	2,062	2,985	N/A	Non-Incen.:	$77	$78	$81	$85	$111	$432				
	Coincident kW:	0	79	269	486	703	N/A	Total:	$81	$175	$294	$323	$333	$1,205				
New Construction Incentive - excluding gov. buildings	Lifetime MWh:	0	306	1,377	2,142	2,448	6,273	Incentive:	$0	$4	$19	$30	$34	$87	4.2	4.9	6.3	1.0
	Annual MWh:	0	15	84	191	314	N/A	Non-Incen.:	$4	$31	$5	$31	$12	$82				
	Coincident kW:	0	3	19	44	72	N/A	Total:	$4	$35	$24	$60	$46	$169				
High-Efficiency Refrigeration Incentive - excluding gov. buildings	Lifetime MWh:	0	0	6,301	0	6,301	12,602	Incentive:	$0	$0	$122	$0	$122	$243	3.2	4.5	4.2	1.0
	Annual MWh:	0	0	630	630	1,260	N/A	Non-Incen.:	$10	$91	$17	$54	$42	$214				
	Coincident kW:	0	0	72	72	143	N/A	Total:	$10	$91	$138	$54	$163	$458				
Energy Star Computer - excluding gov. buildings	Lifetime MWh:	32	205	335	0	0	573	Incentive:	$2	$10	$17	$0	$0	$29	1.8	1.2	*	0.6
	Annual MWh:	8	59	143	143	135	N/A	Non-Incen.:	$26	$12	$15	$2	$5	$60				
	Coincident kW:	1	11	26	26	24	N/A	Total:	$28	$22	$32	$2	$5	$89				
Engagement, Education and Communication - excluding gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$167	$251	$224	$175	$217	$1,034				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$167	$251	$224	$175	$217	$1,034				
Total General Service Program excl. gov. buildings	Lifetime MWh:	32	2,988	14,253	9,274	15,881	42,428	Incentive:	$5	$111	$371	$268	$377	$1,132	1.3	2.1	3.2	0.8
	Annual MWh:	8	408	1,997	3,027	4,693	N/A	Non-Incen.:	$284	$463	$341	$346	$387	$1,822				
	Coincident kW:	1	93	385	627	942	N/A	Total:	$290	$574	$712	$615	$764	$2,954				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,747	10,294	21,319	17,243	23,504	75,108	Incentive:	$56	$219	$474	$380	$477	$1,606	1.3	2.1	2.9	0.8
	Annual MWh:	221	1,167	3,287	4,887	7,098	N/A	Non-Incen.:	$706	$824	$670	$703	$815	$3,718				
	Coincident kW:	77	363	845	1,290	1,800	N/A	Total:	$762	$1,043	$1,145	$1,083	$1,292	$5,325				

Exhibit 5: Portfolio Results Including Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - including gov. buildings	Lifetime MWh:	0	4,314	10,711	12,241	12,241	39,506	Incentive:	$6	$135	$294	$327	$299	$1,062	1.2	3.8	2.4	0.9
	Annual MWh:	0	507	1,731	3,128	4,526	N/A	Non-Incen.:	$81	$77	$66	$72	$127	$425				
	Coincident kW:	0	127	432	781	1,129	N/A	Total:	$88	$213	$360	$400	$427	$1,487				
New Construction Incentive - including gov. buildings	Lifetime MWh:	0	471	2,118	3,295	3,766	9,651	Incentive:	$0	$6	$25	$39	$45	$115	4.7	6.1	6.7	1.0
	Annual MWh:	0	24	129	294	483	N/A	Non-Incen.:	$28	$9	$6	$33	$16	$93				
	Coincident kW:	0	5	30	67	110	N/A	Total:	$28	$15	$32	$72	$61	$208				
High-Efficiency Refrigeration Incentive - including gov. buildings	Lifetime MWh:	0	0	7,580	0	7,580	15,161	Incentive:	$0	$0	$132	$0	$132	$263	3.2	4.3	4.6	1.0
	Annual MWh:	0	0	694	694	1,388	N/A	Non-Incen.:	$36	$100	$19	$86	$49	$290				
	Coincident kW:	0	0	80	80	161	N/A	Total:	$36	$100	$151	$86	$180	$553				
Energy Star Computer - including gov. buildings	Lifetime MWh:	107	681	1,111	0	0	1,899	Incentive:	$6	$35	$57	$0	$0	$98	2.0	1.3	*	0.6
	Annual MWh:	27	197	475	475	448	N/A	Non-Incen.:	$36	$52	$74	$6	$17	$185				
	Coincident kW:	5	35	85	85	80	N/A	Total:	$41	$88	$131	$6	$17	$284				
Engagement, Education and Communication - including gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$202	$290	$255	$200	$252	$1,199				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$202	$290	$255	$200	$252	$1,199				
Total General Service Program incl. gov. buildings	Lifetime MWh:	107	5,466	21,520	15,536	23,587	66,217	Incentive:	$12	$176	$508	$367	$476	$1,538	1.3	2.5	3.2	0.8
	Annual MWh:	27	728	3,029	4,591	6,845	N/A	Non-Incen.:	$383	$529	$420	$398	$461	$2,192				
	Coincident kW:	5	167	627	1,013	1,480	N/A	Total:	$395	$705	$928	$765	$937	$3,730				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,822	12,772	28,586	23,505	31,210	98,896	Incentive:	$63	$284	$612	$478	$576	$2,012	1.4	2.3	2.9	0.8
	Annual MWh:	240	1,487	4,318	6,451	9,250	N/A	Non-Incen.:	$762	$957	$782	$787	$904	$4,191				
	Coincident kW:	81	438	1,087	1,677	2,338	N/A	Total:	$824	$1,240	$1,393	$1,266	$1,480	$6,203				

YEC-YECL-1

Reference: Overall Revenue Requirement – Requested Rate Increases and Revenue Requirement

Request:

(a) Please confirm that the requested year-over-year rate increase is 6.1% for 2013, 3.2% for 2014 and 2.0% for 2015.

(b) If a) is not confirmed, please provide details of the requested year-over-year rate increase calculations for 2013, 2014 and 2015.

(c) Please provide Schedule 8.1 for 2008-2015 without 2013-2015 GRA, i.e. forecast Return on Equity (ROE), equity ratios and Rate Base forecast for 2013-2015 years without GRA application.

Response:

(a) Confirmed.

(b) n/a

(c) Please refer to YEC-YECL-1(c) Attachment 1.

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2008 Actual**						
2	Long-Term Debt	S.8.2 L.19	24,575	56.81%	26,100	6.97%	1,819
3	Common Stock		17,994	41.59%	19,110	7.03%	1,344
4	No Cost Capital	S.8.4 L.8	693	1.60%	735	0.00%	-
5	Total	S.8.5 L.21 S.1.1 L.15	43,262	100.0%	45,946	6.88%	3,163
6	**2009 Actual**						
7	Long-Term Debt	S.8.2 L.42	27,650	57.34%	28,166	6.73%	1,895
8	Common Stock		19,866	41.20%	20,236	11.35%	2,296
9	No Cost Capital	S.8.4 L.8	702	1.45%	715	0.00%	-
10	Total	S.8.5 L.21 S.1.1 L.15	48,217	100.0%	49,116	8.53%	4,191
11	**2010 Actual**						
12	Long-Term Debt	S.8.2 L.63	29,950	57.27%	28,649	6.58%	1,884
13	Common Stock		21,682	41.46%	20,740	10.54%	2,187
14	No Cost Capital	S.8.4 L.8	666	1.27%	637	0.00%	-
15	Total	S.8.5 L.21 S.1.1 L.15	52,298	100.0%	50,026	8.14%	4,071
16	**2011 Actual**						
17	Long-Term Debt	S.8.2 L.85	32,450	57.36%	30,062	6.42%	1,931
18	Common Stock		23,472	41.49%	21,745	10.74%	2,335
19	No Cost Capital	S.8.4 L.8	649	1.15%	601	0.00%	-
20	Total	S.8.5 L.21 S.1.1 L.15	56,571	100.0%	52,408	8.14%	4,266
21	**2012 Actual**						
22	Long-Term Debt	S.8.2 L.107	36,950	58.35%	35,032	6.16%	2,158
23	Common Stock		25,740	40.65%	24,404	10.18%	2,484
24	No Cost Capital	S.8.4 L.8	631	1.00%	598	0.00%	-
25	Total	S.8.5 L.21 S.1.1 L.15	63,321	100.0%	60,034	7.73%	4,642

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**						
27	Long-Term Debt	S.8.3 L.23	43,014	59.49%	43,352	5.88%	2,549
28	Common Stock		28,676	39.66%	28,902	3.08%	890
29	No Cost Capital	S.8.4 L.8	613	0.85%	618	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,303	100.0%	72,872	4.72%	3,439
31	**2014 Test Period**						
32	Long-Term Debt	S.8.3 L.48	51,372	59.59%	52,408	5.71%	2,992
33	Common Stock		34,248	39.72%	34,939	-2.88%	(1,006)
34	No Cost Capital	S.8.4 L.8	595	0.69%	607	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,215	100.0%	87,954	2.26%	1,986
36	**2015 Test Period**						
37	Long-Term Debt	S.8.3 L.73	58,446	59.65%	59,903	5.69%	3,406
38	Common Stock		38,964	39.76%	39,935	-5.32%	(2,124)
39	No Cost Capital	S.8.4 L.8	577	0.59%	591	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	97,987	100.0%	100,430	1.28%	1,282
41	**2008 GRA Approved**						
42	Long-Term Debt	S.8.2 L.126	26,621	59.11%	27,244	6.87%	1,870
43	Common Stock		17,747	39.41%	18,162	9.08%	1,649
44	No Cost Capital	S.8.4 L.8	669	1.49%	685	0.00%	-
45	Total	S.8.5 L.21 S.1.1 L.15	45,037	100%	46,091	7.63%	3,519
46	**2009 GRA Approved**						
47	Long-Term Debt	S.8.2 L.148	29,730	59.17%	29,276	6.60%	1,934
48	Common Stock		19,820	39.45%	19,517	8.92%	1,741
49	No Cost Capital	S.8.4 L.8	695	1.38%	684	0.00%	-
50	Total	S.8.5 L.21 S.1.1 L.15	50,245	100%	49,478	7.43%	3,675

YEC-YECL-2

Reference: Section 2 – Sales and Revenue – Sales Forecast

Request:

(a) Please provide a table with comparison of YECL's forecast (YECL internal and GRA) and actual sales by rate class and by rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) for 2008, 2009, 2010, 2011 and 2012.

(b) Please provide Table 2 on page 2-2 by comparing 2008 - 2009 GRA forecasts to the actual sales, instead of actual normalized sales.

(c) Is the sales forecast method proposed in this application the same as used in YECL's 2008/09 General Rate Application? If not, please enumerate any differences and provide an explanation for why the forecasting method was changed.

Response:

(a) Please refer to YEC-YECL-2(a) Attachment 1 for tables comparing Yukon Electrical's 2008 and 2009 forecast and sales by rate class by rate zone. As lighting rates are the same for all rate zones, the forecast is not available on a rate zone basis. Yukon Electrical did not prepare sales forecasts for 2010, 2011 or 2012 with the same level of detail, rigor or comprehensiveness as it does for GRA test years. Accordingly, Yukon Electrical is not prepared to submit a sales variance comparison for those years as it does not view such a comparison as being appropriate.

(b) Please refer to YEC-YECL-2(b) Schedule 1.

(c) Please refer to YEC-YECL-2(c) Attachment 1.

The Yukon Electrical Company Limited
Sales (MWh) Variance by Rate Zone

Hydro Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	116,772	119,640	2,868	2.5%
Commercial	133,594	132,077	-1,517	-1.1%
Total	250,366	251,717	1,351	0.5%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	119,951	121,938	1,986	1.7%
Commercial	134,812	132,624	-2,188	-1.6%
Total	254,763	254,561	-202	-0.1%

Large Diesel Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	6,318	6,493	174	2.8%
Commercial	7,246	6,597	-650	-9.0%
Total	13,565	13,090	-475	-3.5%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	6,340	6,445	105	1.7%
Commercial	7,377	6,562	-815	-11.0%
Total	13,717	13,006	-710	-5.2%

Small Diesel Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	2,378	1,242	-1,137	-47.8%
Commercial	3,065	2,266	-800	-26.1%
Total	5,444	3,507	-1,937	-35.6%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	1,329	1,212	-117	-8.8%
Commercial	2,382	2,119	-263	-11.1%
Total	3,712	3,331	-381	-10.3%

Old Crow Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	972	928	-44	-4.5%
Commercial	795	765	-31	-3.9%
Total	1,767	1,692	-75	-4.2%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	995	975	-20	-2.0%
Commercial	794	772	-22	-2.8%
Total	1,788	1,747	-41	-2.3%

Total

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	126,441	128,302	1,861	1.5%
Commercial	144,701	141,704	-2,997	-2.1%
Lighting	4,082	4,176	94	2.3%
Total	275,224	274,182	-1,042	-0.4%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	128,615	130,569	1,954	1.5%
Commercial	145,365	142,077	-3,289	-2.3%
Lighting	4,153	4,069	-84	-2.0%
Total	278,133	276,714	-1,419	-0.5%

Table 2
Yukon Electrical Sales Variance
2008-2009 GRA Forecast

2008				
	Forecast (MW.h)	Actual[3] (MW.h)	Variance (MW.h)	(%)
Filed[1]				
Total Sales	269,913	274,182	4,269	1.6
Approved[2]				
Total Sales	275,224	274,182	-1,043	-0.4
2009				
	Forecast (MW.h)	**Actual[3] (MW.h)**	**Variance (MW.h)**	**(%)**
Filed[1]				
Total Sales	272,054	276,714	4,660	1.7
Approved[2]				
Total Sales	278,133	276,714	-1,419	-0.5

1) Schedule 2.1, 2008-2009 GRA

2) Schedule 2.1, Compliance Filing, Board Order 2009-5

3) Line 29, Schedule 2.1, 2013-2015 GRA

A Comparison of Yukon Electrical's GRA Sales Forecast Methodologies

Revenue Class/Variable	2008-2008 GRA	2013-2015 GRA	Rationale
Residential:			
Customer	· Based on Yukon Electrical's work in the community and consultation with local officials/developers and the Yukon Gov't and trend analysis.	· The same approach as in the 2008-2009 GRA.	
UPC	· For all communities with the exception of Whitehorse and Watson Lake, the most recent 3-year average UPC was used. · For Whitehorse and Watson Lake, the most recent 3-year average weather-normalized UPC.	· For all communities with the exception of Keno City, Stewart Crossing, Swift River and Whitehorse, the most recent 3-year average weather-normalized UPC. · For Keno City, Stewart Crossing and Swift River, the most recent 3-year average UPC because there are very few customers in these communities and a poor correlation between their average UPC and HDD. · For Whitehorse, 2013 was forecast by escalating the 2012 normalized UPC by the 3-year average growth rate of normalized UPC, and was kept constant for 2014 and 2015.	· YECL believes using a weather-normalized approach, whenever possible, which eliminates the impact of an abnormally cold/warm year, is a preferable method of forecasting energy consumption for a jurisdiction.
Commercial:			
Customer	· Based on YECL's work in the community and consultation with local officials/developers and the Yukon Gov't. and trend analysis.	· The same approach as in the 2008-2009 GRA.	
UPC	· For all communities with the exception of Whitehorse and Watson Lake, the most recent 3-year average UPC was used. · For Whitehorse and Watson Lake, the most recent 3-year average weather-normalized UPC.	· The same approach as in the 2008-2009 GRA for all communities except for Watson Lake where the base year UPC was forecast based on the most recent 3-year average UPC.	· Watson Lake R^2 is low.

Lighting:	· Based on YECL's work in the community and consultation with local officials/developers number of lights (streetlights and private lights) · Energy for streetlights and private lights is calculated by multiplying the number of lights with average use per light.	· The same approach as in the 2008-2009 GRA · The same approach as in the 2008-2009 GRA	No new LED conversions are incorporated into the forecast and average use per light is constant. Therefore, the main driver of the energy forecast is the additional number of lights.

YEC-YECL-3

Reference: Section 2 – Sales and Revenue – Residential Sales Forecast

Request:

(a) Please provide details of residential customer forecast for 2013, 2014 and 2015. Please include list of "all known residential property developments" (page 2-5, line 1) included in forecast as well as the estimated additional number of customers for each development area.

(b) Does the residential customer forecast also consider population growth forecasts? If so please provide the source of the population growth forecasts. If not, please explain why population growth forecasts are not considered.

(c) Please provide the impact for each forecast year of using the three-year average usage per customer (UPC) for Whitehorse. Please provide calculations in an excel file.

(d) Given the poor R2 correlation factor for residential customer UPC using single variable regression did YECL consider multiple variable regression analysis for UPC? If not, why not.

(e) Please provide any assessments as to sensitivity of such regressions as between different months or seasons.

(f) Please confirm that YECL used a twenty year rolling average of Heating Degree Days (HDD) [page 2-5, line 22].

(g) If f) above is confirmed please explain why attachments 1 through 21 show data only for 1998-2012. Please provide calculations in an excel file.

(h) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in excel file.

Response:

(a) Details of residential customer forecast with all known residential property developments are provided in YEC-YECL-3(a) Attachment 1.

(b) No, Yukon Electrical did not consider the population growth because we are not aware of the availability of a population forecast for the test period by community from a reliable independent source, which can be used in its customer count forecast.

(c) Please refer to YEC-YECL-3(c) Attachment 1.

(d) Yukon Electrical did not consider the use of a multi-variant regression because adding more independent variables to the regression equation, the sole purpose of which is to identify and quantify the impact of weather on average consumption, would obscure the impact of the weather variable.

In addition, as Attachment 21 of the Application indicates, the R^2 for the regression between UPC and HDD for the various communities ranges between 50% to 84%, with a t-stat greater than 2. This indicates that the HDD variable is significant at a 5% confidence interval. In other words the temperature (HDD) is responsible for at least 50% to 84% of variations in average electricity consumption in those communities. Given the small size of these communities and the lack of appropriate data, Yukon Electrical believes it is reasonable to use the approach it has used in forecasting the future energy consumption for the test period.

(e) If Yukon Electrical's understanding of this question is correct, the question is asking to perform 320 regressions, (20 communities * (12 months + 4 seasons)) for the assessment of the monthly and seasonal sensitivities. Yukon Electrical does not see the relevance of this question with respect to its proposed sales forecast and, given the significant amount of work it entails, is not prepared to complete the analysis to answer the question.

(f) Confirmed.

(g) Yukon Electrical used 15 years of data for the UPC and HDD regression because that is the highest number of years for which Yukon Electrical has data for all communities. Please refer to YUB-YECL-57 Attachments for details.

(h) Please refer to YEC-YECL-3(h) Attachment 1 for billed sales by month for each test year by rate zone. The forecast is created on a monthly billed basis and is then converted to an earned forecast, which aligns with Schedule 2.1 in this Application.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Residential Customer Forecast by Community

Communities	2013	2014	2015
Carmacks	215	219	223
Carcross	253	257	261
Haines Junction	390	397	404
Teslin	280	285	290
Upper Liard	54	55	56
Destruction Bay	96	98	100
Whitehorse	10,792	10,975	11,161
Beaver Creek	72	73	74
Watson Lake	593	603	614
Old Crow	144	146	149
Keno City	42	43	44
Stewart Crossing	13	13	13
Lower Post B.C.	56	57	58
Ross River	180	183	186
Pelly Crossing	155	158	161
Swift River	2	2	2
Tagish	347	353	359
Marsh Lake	437	444	452
Deep Creek	41	42	43
Minto Landing	-	-	-
TOTAL Residential	14,159	14,401	14,647

Known Residential Property Developments

	Customer Adds		
Projects	2013	2014	2015
Mah's Point	53	-	-
Rivers Edge	15	-	-
Yukon Housing Development 4th Ave	16	-	-
Whistle Bend stage 1,2,3	25	20	20
Crocus Glen	9	9	7
Evergreen	27	20	-
Brookside Place	14	8	8
Grizzly Valley	5	3	3
Ingram	13	5	-
TTC	4	5	5
Lower Post	10	6	-
Raven Ridge	2	5	3
Other Customer Adds	109	161	200
Total Adds	302	242	246

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	Annual UPC (kWh)
Jan-98	1334.11	1165.70	1,295		
Feb-98	1071.75	719.10	1,134		
Mar-98	1027.75	756.60	1,043		
Apr-98	902.89	458.60	921		
May-98	787.72	270.60	815		
Jun-98	696.64	119.50	719		
Jul-98	627.52	111.60	628		
Aug-98	604.15	189.20	592		
Sep-98	706.17	327.80	699		
Oct-98	780.59	557.70	772		
Nov-98	922.54	792.30	936		
Dec-98	970.68	1051.80	927		
Jan-99	1383.18	1183.10	1,334		
Feb-99	1164.46	976.40	1,088		
Mar-99	1040.97	734.00	1,069		
Apr-99	944.37	508.80	936		
May-99	811.83	391.90	774		
Jun-99	754.75	153.90	758		
Jul-99	646.43	108.60	649		
Aug-99	610.64	145.70	621		
Sep-99	697.48	311.20	700		
Oct-99	763.70	499.80	786		
Nov-99	881.73	792.50	895		
Dec-99	994.21	844.00	1,062		
Jan-00	1264.66	1082.90	1,270		
Feb-00	1036.07	735.20	1,090		
Mar-00	918.53	659.20	986		
Apr-00	854.15	515.60	842		
May-00	846.79	382.00	815		
Jun-00	731.77	172.50	725		
Jul-00	656.21	142.10	641		
Aug-00	620.05	219.90	591		
Sep-00	733.99	354.20	713		
Oct-00	787.21	539.20	788		
Nov-00	884.41	691.20	952		
Dec-00	940.26	977.80	936		
Jan-01	1185.33	722.70	1,384		
Feb-01	938.26	864.10	922		
Mar-01	987.72	765.30	998		
Apr-01	867.85	506.80	860		
May-01	816.38	390.40	780		
Jun-01	763.40	167.30	760		
Jul-01	657.29	139.60	643		
Aug-01	598.61	139.60	613		
Sep-01	660.89	309.00	664		
Oct-01	754.64	573.40	737		
Nov-01	904.51	818.00	904		
Dec-01	1056.40	1094.60	989		
Jan-02	1223.01	935.60	1,307		
Feb-02	1013.30	824.60	1,019		
Mar-02	997.99	921.10	925		
Apr-02	990.09	653.30	904		
May-02	798.77	361.60	777		
Jun-02	707.08	175.60	699		
Jul-02	642.71	130.90	633		
Aug-02	648.08	182.80	639		
Sep-02	680.33	314.40	681		
Oct-02	758.56	444.30	811		
Nov-02	873.29	582.60	999		
Dec-02	898.43	845.20	966		

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	Annual UPC (kWh)
Jan-03	1202.44	989.10	1,258		
Feb-03	995.15	756.60	1,037		
Mar-03	985.34	834.50	959		
Apr-03	892.59	514.30	881		
May-03	790.52	363.70	768		
Jun-03	749.45	192.80	732		
Jul-03	657.75	84.40	673		
Aug-03	617.42	180.60	609		
Sep-03	709.08	359.20	685		
Oct-03	726.71	466.70	767		
Nov-03	910.68	874.60	880		
Dec-03	1072.98	911.60	1,104		
Jan-04	1245.81	1257.90	1,157		
Feb-04	1092.27	697.20	1,166		
Mar-04	923.71	753.50	941		
Apr-04	948.79	466.60	963		
May-04	751.60	272.50	778		
Jun-04	711.26	83.70	753		
Jul-04	667.46	74.20	688		
Aug-04	607.29	101.70	642		
Sep-04	669.67	367.50	642		
Oct-04	761.52	540.50	762		
Nov-04	897.87	719.80	950		
Dec-04	1015.36	899.50	1,053		
Jan-05	1277.77	1165.80	1,238		
Feb-05	1107.70	795.20	1,129		
Mar-05	922.86	613.70	1,015		
Apr-05	906.16	453.30	928		
May-05	734.86	256.60	770		
Jun-05	705.13	154.40	709		
Jul-05	660.11	132.60	650		
Aug-05	621.38	150.80	629		
Sep-05	741.98	299.30	751		
Oct-05	733.74	534.60	737		
Nov-05	921.61	762.60	951		
Dec-05	967.23	794.40	1,062		
Jan-06	1196.53	1096.20	1,195		
Feb-06	1043.82	821.30	1,051		
Mar-06	1072.57	906.30	1,007		
Apr-06	933.65	519.10	920		
May-06	801.77	346.90	788		
Jun-06	726.49	173.10	720		
Jul-06	704.17	118.40	701		
Aug-06	635.06	201.60	616		
Sep-06	736.28	295.70	747		
Oct-06	795.22	520.50	806		
Nov-06	938.75	1162.20	753		
Dec-06	1130.58	824.30	1,209		
Jan-07	1245.66	912.00	1,343		
Feb-07	1050.91	998.80	962		
Mar-07	1139.27	954.20	1,048		
Apr-07	985.39	511.90	975		
May-07	735.33	322.10	735		
Jun-07	719.79	140.50	731		
Jul-07	702.49	102.30	708		
Aug-07	597.33	154.20	604		
Sep-07	688.79	308.40	692		
Oct-07	754.77	543.70	753		
Nov-07	922.64	724.60	972		
Dec-07	995.15	1069.50	942		

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)		Annual UPC (kWh)
Jan-08	1298.44	1113.80	1,287			
Feb-08	1185.79	954.60	1,121			
Mar-08	1011.53	734.70	1,039			
Apr-08	942.12	517.30	929			
May-08	788.52	307.90	796			
Jun-08	696.47	225.60	662			
Jul-08	680.93	173.40	648			
Aug-08	700.97	187.70	689			
Sep-08	700.67	318.70	699			
Oct-08	732.64	563.00	721			
Nov-08	984.81	782.50	1,003			
Dec-08	1011.40	1186.20	895			
Jan-09	1528.55	1137.90	1,504			
Feb-09	1122.38	955.40	1,057			
Mar-09	1093.54	868.50	1,049			
Apr-09	945.55	515.20	934			
May-09	773.10	331.20	768			
Jun-09	704.15	144.10	713			
Jul-09	702.59	62.50	730			
Aug-09	627.45	158.30	632			
Sep-09	719.71	306.10	725			
Oct-09	771.84	541.80	771			
Nov-09	953.63	781.50	973			
Dec-09	1013.21	943.40	1,027	10882.60		
Jan-10	1345.94	991.10	1,401			
Feb-10	1012.55	679.20	1,096			
Mar-10	940.25	656.00	1,010			
Apr-10	944.91	461.20	962			
May-10	795.15	292.00	811			
Jun-10	719.19	171.90	713			
Jul-10	685.61	117.30	683			
Aug-10	627.66	146.20	638			
Sep-10	720.70	332.40	711			
Oct-10	821.83	520.40	833			
Nov-10	904.24	717.60	958			
Dec-10	1057.11	1162.50	953	10770.18		10,575
Jan-11	1436.52	1010.20	1,481			
Feb-11	1129.49	905.60	1,091			
Mar-11	1256.14	901.70	1,193			
Apr-11	955.17	511.20	945			
May-11	892.99	296.20	907			
Jun-11	743.84	161.00	744			
Jul-11	677.48	127.80	670			
Aug-11	647.93	217.90	620			
Sep-11	737.64	328.50	731			
Nov-11	831.75	513.30	847			
Nov-11	943.59	936.25	879			
Dec-11	1136.92	775.10	1,242	11349.30		11,389
Jan-12	1356.98	1118.10	1,343			
Feb-12	1170.51	707.50	1,239			
Mar-12	1098.22	756.20	1,114			
Apr-12	930.47	450.60	953			
May-12	835.03	350.80	820			
Jun-12	770.21	200.00	749			
Jul-12	708.91	140.10	694			
Aug-12	677.42	157.90	682			
Sep-12	695.14	287.15	710			
Oct-12	802.64	631.40	754			
Nov-12	1011.59	969.60	929			
Dec-12	1262.76	1196.80	1,141	11128.22	0.7%	11,320

	Using 3-yr Avg UPC (kWh)	Δ (kWh)	Whitehorse Customer Forecast (annual Avg)	Energy Impact Whitehorse (MWh)
2013-F	11,095	(116)	10,792	(1,257)
2014-F	11,095	(116)	10,975	(1,279)
2015-F	11,095	(116)	11,161	(1,300)

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Residential Regression Results (Yukon Electrical 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

The Yukon Electrical Company Limited
Residential Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	14,196	13,316	11,120	10,219	8,680	7,654	7,456	7,799	7,809	8,251	11,001	11,466	118,968	119,640
2009	17,006	12,669	12,236	10,597	8,732	7,877	7,939	7,105	8,121	8,857	10,838	11,666	123,642	121,938
2010	15,357	11,603	10,761	10,802	9,097	8,170	7,947	7,262	8,338	9,550	10,574	12,450	121,911	122,732
2011	16,897	13,265	14,626	11,210	10,426	8,653	8,025	7,693	8,787	9,858	11,406	13,655	134,500	132,820
2012	16,437	14,137	13,323	11,090	10,060	9,326	8,544	8,309	8,557	9,883	12,686	15,764	138,117	141,284
2013 F	16,936	15,348	13,909	11,867	10,255	9,294	8,688	8,534	9,001	9,612	11,870	14,500	139,815	143,018
2014 F	17,225	15,609	14,147	12,069	10,430	9,453	8,837	8,680	9,154	9,776	12,073	14,748	142,201	145,460
2015 F	17,522	15,877	14,389	12,273	10,607	9,617	8,989	8,828	9,311	9,944	12,276	14,999	144,632	147,947

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	793	718	576	549	473	402	416	420	419	474	578	638	6,456	6,493
2009	826	660	619	568	479	409	424	390	444	476	557	683	6,535	6,445
2010	788	614	558	548	464	418	401	379	432	518	533	652	6,305	6,352
2011	820	624	692	574	490	434	386	405	462	476	559	653	6,577	6,496
2012	808	658	618	549	501	434	413	404	384	486	544	690	6,488	6,617
2013 F	792	604	589	536	474	419	394	388	421	474	502	627	6,222	6,345
2014 F	806	614	599	545	482	426	401	395	428	482	511	637	6,328	6,454
2015 F	820	625	609	555	491	434	408	402	436	491	520	649	6,439	6,567

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	138	125	110	110	95	92	81	88	79	82	109	126	1,235	1,242
2009	141	127	118	115	90	78	87	79	87	90	107	111	1,229	1,212
2010	153	116	103	108	98	80	84	72	83	93	103	111	1,206	1,210
2011	148	130	122	114	91	83	83	83	88	97	117	147	1,303	1,290
2012	162	133	131	99	87	99	83	89	86	99	121	153	1,341	1,373
2013 F	161	132	122	110	93	88	84	82	87	98	112	137	1,306	1,337
2014 F	163	135	125	112	95	89	85	84	89	99	114	139	1,328	1,360
2015 F	166	137	127	114	97	91	86	85	90	101	116	141	1,351	1,383

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	91	104	75	77	76	78	57	76	64	57	89	78	922	928
2009	120	88	90	91	84	71	75	57	60	84	88	80	989	975
2010	112	94	87	104	67	62	71	58	67	84	81	89	975	979
2011	147	106	94	121	96	64	76	64	73	72	80	114	1,108	1,089
2012	110	104	119	94	80	81	61	83	49	72	92	112	1,058	1,076
2013 F	128	107	104	110	84	71	71	70	64	77	84	105	1,075	1,092
2014 F	130	108	105	112	85	72	72	71	65	78	85	107	1,090	1,107
2015 F	132	110	107	114	86	73	73	72	67	79	87	109	1,108	1,126

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	15,218	14,264	11,882	10,954	9,324	8,226	8,010	8,384	8,371	8,865	11,777	12,307	127,581	128,302
2009	18,093	13,543	13,062	11,371	9,384	8,435	8,525	7,631	8,712	9,507	11,590	12,542	132,394	130,569
2010	16,409	12,427	11,511	11,562	9,726	8,730	8,503	7,770	8,920	10,246	11,292	13,303	130,397	131,273
2011	18,012	14,125	15,534	12,018	11,103	9,234	8,570	8,246	9,411	10,503	12,162	14,569	143,488	141,696
2012	17,518	15,032	14,189	11,833	10,729	9,940	9,100	8,885	9,076	10,541	13,443	16,719	147,005	150,350
2013 F	18,017	16,191	14,724	12,623	10,906	9,872	9,237	9,075	9,574	10,261	12,568	15,369	148,417	151,793
2014 F	18,325	16,467	14,975	12,838	11,092	10,040	9,395	9,229	9,737	10,436	12,783	15,631	150,947	154,381
2015 F	18,640	16,748	15,232	13,055	11,281	10,214	9,557	9,387	9,905	10,616	12,999	15,898	153,530	157,023

YEC-YECL-4

Reference: Section 2 – Sales and Revenue – Commercial Sales Forecast

Request:

(a) Please provide details of commercial customer forecast for 2013, 2014 and 2015. Please include a list of the twelve new large commercial customers with the forecast load for each customer for all test years. Provide for each year included in the GRA (2010-2015) the number of new commercial customers in Whitehorse and the average UPC each year for these new customers.

(b) Please confirm that for Watson Lake the most recent three-year average actual UPC was used.

(c) Please discuss why weather normalized UPC is not used for commercial sales forecast.

(d) Please provide the impact for each forecast year of using the three-year average UPC for Whitehorse. Please provide calculations in an excel file.

(e) Please provide the 2012 actual loads for the "several secondary commercial customers" who converted to primary service as referenced (page 2-12, lines 13-15).

(f) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in an excel file.

Response:

(a) Please refer to the response to information request CW-YECL-3.

(b) Confirmed.

(c) As stated on Page 2-5 and 2-6 of the Application, actual weather-normalized UPC is used for determining the forecast of the commercial sales in Whitehorse. However, weather normalization was not used for the remaining communities

because of a poor correlation between the average UPC and HDD for those individual communities.

(d) As indicated in YEC-YECL-4(d) Attachment 1, the 3 year average actual commercial UPC would result in a lower energy forecast than the proposed values in Yukon Electrical's 2013-15 GRA.

(e) As detailed in the table below, the 2012 actual load for the 12 customers who converted from secondary to primary service was 2,489 MWh.

Customer ID	Load (MWh)
Customer 1	163
Customer 2	17
Customer 3	42
Customer 4	86
Customer 5	19
Customer 6	2
Customer 7	292
Customer 8	-
Customer 9	-
Customer 10	6
Customer 11	1,862
Customer 12	-
Total	2,489

(f) Please refer to YEC-YECL-4(f) Attachment 1 for billed sales by month for each test year by rate zone. The forecast is created on a monthly billed basis and then converted to an earned forecast which aligns with Schedule 2.1 of the Application.

The Yukon Electrical Company Limited
Commercial UPC and Energy - 3 Year Average Actual vs Normalized

	Annual 3 Year Average Actual UPC (kWh)	Annual Normalized UPC (kWh)	Annual Average Customer (kWh)
2013	66,969	67,270	2,031
2014	66,969	67,923	2,055
2015	66,969	68,355	2,087

	Annual 3 Year Average Actual UPC_Energy (MWh)	Annual Normalized UPC_Energy (MWh)	Difference (MWh)
2013	135,993	136,605	(612)
2014	137,619	139,580	(1,961)
2015	139,732	142,625	(2,893)

The Yukon Electrical Company Limited
Commercial Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	13,392	12,880	11,297	11,722	9,798	9,904	9,341	10,749	9,755	9,835	11,687	11,359	131,719	132,077
2009	14,786	11,791	12,440	11,488	10,082	9,653	10,555	10,021	9,513	9,958	11,427	11,340	133,054	132,623
2010	14,052	11,787	11,604	11,971	10,395	10,468	10,089	10,026	9,787	10,573	12,084	12,272	135,110	136,223
2011	15,259	12,317	13,877	11,825	11,360	10,549	10,410	10,269	10,712	11,075	12,068	13,033	142,755	141,006
2012	15,677	13,178	13,063	12,764	11,533	10,991	10,836	10,520	10,157	11,438	12,490	13,993	146,641	149,182
2013 F	16,004	13,804	13,413	13,209	11,728	11,111	10,901	10,807	10,590	11,566	12,298	13,683	149,115	151,698
2014 F	16,341	14,121	13,728	13,498	12,008	11,384	11,173	10,924	10,712	11,816	12,580	13,991	152,277	154,915
2015 F	16,688	14,435	14,037	13,804	12,293	11,660	11,446	11,189	10,969	11,969	12,789	14,243	155,521	158,215

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	621	641	583	544	526	497	535	555	473	466	568	570	6,579	6,597
2009	670	591	566	540	496	481	531	503	480	542	685	499	6,583	6,562
2010	681	640	571	579	473	474	519	489	414	596	574	609	6,619	6,681
2011	703	575	646	538	512	494	477	406	494	527	599	641	6,611	6,537
2012	782	633	666	587	565	558	494	533	607	374	661	707	7,165	7,287
2013 F	740	633	649	582	497	470	494	475	527	514	639	694	6,913	7,030
2014 F	776	670	687	620	535	509	498	479	533	520	647	704	7,179	7,300
2015 F	787	680	697	629	543	517	505	486	540	528	657	714	7,284	7,408

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	214	242	142	183	205	174	192	225	173	144	185	181	2,260	2,266
2009	222	201	176	184	144	168	205	180	181	177	123	165	2,126	2,119
2010	216	173	162	168	161	180	200	195	172	164	167	166	2,123	2,135
2011	224	175	193	184	212	176	181	197	192	163	168	184	2,250	2,222
2012	231	179	184	164	152	195	170	202	175	161	172	174	2,157	2,191
2013 F	215	168	172	153	145	149	149	159	151	140	155	170	1,926	1,956
2014 F	218	171	175	155	148	152	152	161	153	142	157	173	1,956	1,987
2015 F	222	174	178	158	150	154	154	164	156	145	160	176	1,989	2,020

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	67	83	67	61	64	65	46	63	51	46	78	71	763	765
2009	86	64	77	74	69	53	66	46	45	67	59	69	775	772
2010	82	65	65	80	54	54	48	46	47	60	66	66	734	737
2011	87	80	73	73	73	62	62	55	61	59	69	83	838	826
2012	82	74	96	81	65	74	52	71	50	65	65	111	887	903
2013 F	90	78	84	84	68	68	57	59	55	63	69	90	866	881
2014 F	91	79	85	86	69	69	58	60	56	64	70	91	878	893
2015 F	93	80	86	87	70	70	59	61	56	65	71	92	891	906

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	14,295	13,845	12,090	12,510	10,593	10,640	10,114	11,592	10,451	10,492	12,517	12,181	141,320	141,704
2009	15,764	12,647	13,260	12,285	10,791	10,355	11,358	10,749	10,218	10,744	12,294	12,073	142,538	142,076
2010	15,031	12,664	12,402	12,799	11,083	11,176	10,856	10,756	10,421	11,393	12,891	13,114	144,586	145,776
2011	16,274	13,146	14,790	12,621	12,156	11,282	11,130	10,928	11,460	11,824	12,904	13,942	152,454	150,591
2012	16,772	14,064	14,009	13,595	12,315	11,817	11,552	11,327	10,989	12,038	13,389	14,985	156,851	159,562
2013 F	17,049	14,683	14,317	14,028	12,438	11,799	11,602	11,500	11,323	12,284	13,160	14,637	158,819	161,564
2014 F	17,426	15,041	14,674	14,359	12,760	12,114	11,882	11,626	11,453	12,543	13,453	14,959	162,290	165,095
2015 F	17,789	15,370	14,998	14,677	13,056	12,400	12,165	11,900	11,721	12,707	13,676	15,225	165,685	168,549

YEC-YECL-5

Reference: Section 2 – Sales and Revenue – Lighting Sales Forecast

Request:

(a) Please provide forecast method for streetlight sales, including average usage per light for each lighting type (kW.h/year/light type) and number of lights by lighting type and by community.

(b) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in excel file.

Response:

(a) Forecast Method for streetlight sales:

Streetlight Energy Sales = (Number of streetlights) x (Average use per light)

Rate	Light Type	Use per light (kwh)		
		2013	2014	2015
6110	175W	72	72	72
6120	250W	97	97	97
6130	400W	157	157	157
6140	100W	40	40	40
6180	250W	101	101	101
6190	400W	158	158	158
6360	150W	59	59	59
6580	250W	101	101	101
6590	400W	158	158	158
6640	70W	27	27	27
6720	250W	97	97	97
6780	250W	101	101	101
6790	400W	158	158	158

Rate	Light Type	Number of Streetlights (average)		
		2013	2014	2015
6110	175W	0	0	0
6120	250W	22	22	22
6130	400W	0	0	0
6140	100W	3,214	3,225	3,236
6180	250W	1,243	1,280	1,317
6190	400W	21	21	21
6360	150W	374	392	410
6580	250W	105	105	105
6590	400W	53	53	53
6640	70W	104	109	114
6720	250W	32	32	32
6780	250W	15	15	15
6790	400W	15	15	15

Please note that the number of lights by community is not available, but only by rate and light type.

(b) Please refer to YEC-YECL-5(b) Attachment 1 for billed sales by month for each test year by rate zone. The lighting forecast is created by rate code and not by rate zone as all the rate zones share the same rate.

The Yukon Electrical Company Limited
Lighting Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	301	302	302	303	305	304	305	304	305	305	342	332	3,709	3,743
2009	302	303	300	300	302	308	303	303	303	333	317	317	3,692	3,654
2010	317	317	318	319	317	317	318	317	317	314	320	317	3,809	3,821
2011	318	318	318	317	318	318	314	319	330	318	318	317	3,821	3,767
2012	318	336	322	321	321	321	321	320	321	320	320	319	3,861	3,910
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	23	23	23	23	23	23	23	23	23	23	26	24	279	281
2009	22	23	23	23	23	23	23	23	23	23	23	22	271	268
2010	23	23	23	23	23	22	22	22	22	22	22	22	269	270
2011	22	22	22	22	23	22	22	22	22	22	22	22	268	265
2012	22	22	22	22	22	22	22	22	22	22	22	22	267	270
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	10	10	10	10	10	10	10	10	10	10	12	11	125	126
2009	10	10	10	10	10	10	10	10	10	10	10	10	123	122
2010	10	11	10	10	10	10	10	10	10	10	10	10	124	124
2011	10	10	10	10	10	10	10	10	10	10	10	10	124	122
2012	10	10	10	10	10	10	10	10	10	10	10	10	124	125
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	2	2	2	2	2	2	2	2	2	2	2	2	26	26
2009	2	2	2	2	2	2	2	2	2	2	2	2	25	25
2010	2	2	2	2	2	2	2	2	2	2	2	2	25	26
2011	2	2	2	2	2	2	2	2	2	2	2	2	25	25
2012	2	2	2	2	2	2	2	2	2	2	2	2	25	26
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	336	338	337	338	340	339	340	340	340	340	381	370	4,139	4,176
2009	337	338	335	335	337	343	338	338	338	368	352	352	4,111	4,069
2010	352	352	353	354	352	352	352	352	352	349	355	352	4,228	4,241
2011	353	352	352	351	353	352	349	353	365	352	352	352	4,239	4,179
2012	353	371	357	356	356	356	355	355	355	355	355	354	4,278	4,332
2013 F	355	355	355	355	355	355	355	355	360	360	360	360	4,279	4,279
2014 F	360	360	360	360	360	360	360	360	364	364	364	364	4,334	4,334
2015 F	364	364	364	364	364	364	364	364	369	369	369	369	4,388	4,388

YEC-YECL-6

Reference: Section 2 – Sales and Revenue – Industrial Sales Forecast

Request:

(a) Please provide details of the industrial load forecast, including the forecast provided by Whitehorse Copper Tailings (WHCT).

(b) Please provide monthly sales and demand forecasts.

(c) Please discuss winter load requirements for WHCT, if any.

(d) Please provide details of the proposed deferral account relating to WHCT sales uncertainty, including trigger points when the difference between forecast and actual will be refunded to or collected from customers, and how YECL proposes to collect/refund the difference. Please provide examples by assuming WHCT actual sales for the test years are higher than forecast and lower than forecast.

(e) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(f) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a - b) Please refer to UCG-YECL-8(e) Attachment 1. Whitehorse Copper Tailings provided load and the approximate start-up time in which Yukon Electrical based the sales forecast on.

(c) WHCT has advised Yukon Electrical that it intends on being in operation for 9 months in a year: March to November.

(d) Unless the deferral account grows to greater than 0.5% of Yukon Electrical's revenue requirement (approximately $300,000), Yukon Electrical would propose to collect/refund the difference as part of its next GRA. If the deferral did grow to this level, Yukon Electrical would make an application to the Board to dispense

of the balance. Please refer to YEC-YECL-6(d) Attachment 1 for an example of the proposed deferral calculation assuming WHCT sales are higher than forecast or lower than forecast, as well as if WHCT does not start up operations in 2013-2015.

(e) Not confirmed. No industrial customers were forecast as part of Yukon Electrical's 2008/2009 GRA. Therefore, the requested deferral account does not reduce Yukon Electrical's risk profile but rather keeps it constant.

(f) Yukon Electrical is aware of one example in the Yukon in 1998 where the Board ordered the creation of a deferral account related to the sales of Yukon Energy to the Faro mine site under Rate Schedule 34. In Board Order 1998-5, the Board stated:

> All revenue derived from Rate Schedule 34, less reasonable incremental costs associated with supplying the Faro mine site under this rate schedule, shall be placed in a deferral account for subsequent application to the benefit of customers as directed by the Board.

Other than the above example, Yukon Electrical is not aware of similar deferral accounts used by other regulated utilities in Canada that would be applicable to the unique start-up timing and load uncertainties currently being faced by Yukon Electrical as part of this Application.

The Yukon Electrical Company Limited
Sample Calculation of Proposed Whitehorse Copper Tailings Deferral

	2013	2014	2015
Forecast Load (MWh) (per Schedule 2.1 of the Application)	1,025	4,620	4,620
Forecast Revenue per kWh (per Schedule 2.1 of the Application)	$ 0.1391	$ 0.1326	$ 0.1326
Forecast Purchase Power Rate per kWh (per Schedule 3.1 of the Application)	$ 0.0830	$ 0.0830	$ 0.0830
Forecast Line Losses (Per Schedule 3.2 of the Application)	6.2%	6.2%	6.2%
Scenario #1 - Whitehorse Copper Load is 50% Lower Than Forecast			
Actual Load (MWh)	512	2,310	2,310
Change in Revenues	$ 71,289	$ 306,198	$ 306,198
Change in Purchase Power Costs	$ (45,155)	$ (203,568)	$ (203,568)
Amount to Be Collected From (Refunded To) Customers	$ 26,134	$ 102,630	$ 102,630
Scenario #2 - Whitehorse Copper Load is 50% Higher Than Forecast			
Actual Load (MWh)	1,537	6,930	6,930
Change in Revenues	$ (71,289)	$ (306,198)	$ (306,198)
Change in Purchase Power Costs	$ 45,155	$ 203,568	$ 203,568
Amount to Be Collected From (Refunded To) Customers	$ (26,134)	$ (102,630)	$ (102,630)
Scenario #3 - Whitehorse Copper Does Not Start Operations in the Test Period			
Actual Load (MWh)	-	-	-
Change in Revenues	$ 142,579	$ 612,396	$ 612,396
Change in Purchase Power Costs	$ (90,310)	$ (407,136)	$ (407,136)
Amount to Be Collected From (Refunded To) Customers	$ 52,269	$ 205,260	$ 205,260

YEC-YECL-7

Reference: Section 2 – Sales and Revenue – YECL/YEC Retail Revenue

Request:

(a) Please provide details of the YECL revenue forecast calculation by rate class for each test year, including assumed average rate per kW.h, assumed sales and revenue by rate blocks for each rate class and assumed sales and revenue by government and non-government customer type for each rate class.

(b) Please provide details of YEC revenue forecast calculation for test year as shown in Schedule 2.1.

Response:

(a) Please refer to YEC-YECL-7(a) Attachment 1 for the requested calculations.

(b) Please refer to YEC-YECL-7(b) Attachment 1 for the details of the Yukon Energy revenue forecast for the test years as provided by Yukon Energy by e-mail on May 3, 2013.

RESIDENTIAL AND COMMERCIAL RATES

(Applies to 2013-2015 Revenue on Existing Rates)

Existing Rates	Customer Charge	Energy $/kWh Block 1	Energy $/kWh Block 2	Energy $/kWh Block 3	Energy $/kWh Block 4	Demand Charge per kW
1160 - Res-Hydro Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1180 - Res-Hydro Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1260 - Res-Small Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1280 - Res-Small Diesel Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1360 - Res-Large Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1380 - Res-Large Diesel Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1460 - Res-Old Crow Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.3077		$0
1480 - Res-Old Crow Diesel Govt	$18.47	$0.1647	$0.1747	$0.4145		$0
2160 - Com-Hydro Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2170 - Com-Hydro Govt-Muni	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2180 - Com-Hydro Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.1286	$12.31
2260 - Com-Small Diesel Non-govt	$0	$0.1000	$0.1288	$0.1568	$0.1522	$7.39
2280 - Com-Small Diesel Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.1522	$12.31
2360 - Com-Large Diesel Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2370 - Com-Large Diesel Govt-Muni	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2380 - Com-Large Diesel Govt-Federal	$0	$0.1381	$0.1500	$0.2000	$0.1286	$12.31
2460 - Com-Old Crow Diesel Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.3172	$7.39
2480 - Com-Old Crow Diesel Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.3172	$12.31

RESIDENTIAL AND COMMERCIAL 2013 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2013 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	155,628	110,819,077	27,065,347	3,496,429		141,380,853	
1180 - Res-Hydro Govt	2,086	1,270,414	334,489	32,514		1,637,417	
1260 - Res-Small Diesel Non-Govt	1,831	967,445	146,469	8,162		1,122,076	
1280 - Res-Small Diesel Govt	204	168,610	44,088	2,068		214,767	
1360 - Res-Large Diesel Non-Govt	8,022	5,134,912	900,803	59,411		6,095,126	
1380 - Res-Large Diesel Govt	408	218,770	29,118	2,369		250,257	
1460 - Res-Old Crow Diesel Non-Govt	1,608	898,499	63,134	16,313		977,945	
1480 - Res-Old Crow Diesel Govt	120	71,337	24,495	18,525		114,358	
Total - Residential		**119,549,065**	**28,607,944**	**3,635,791**		**151,792,800**	
2160 - Com-Hydro Non-Govt	23,575	29,622,363	35,549,026	3,998,752	22,429,035	91,599,177	415,616
2170 - Com-Hydro Govt-Muni	2,126	1,807,453	3,725,823	674,590	6,743,570	12,951,435	51,654
2180 - Com-Hydro Govt-Fed	4,595	5,322,765	12,962,502	2,772,624	26,089,167	47,147,058	162,551
2260 - Com-Small Diesel Non-govt	648	706,226	556,920	2,751	365	1,266,262	7,114
2280 - Com-Small Diesel Govt-Fed	539	415,716	273,122	568	0	689,406	4,182
2360 - Com-Large Diesel Non-Govt	1,758	2,269,788	2,264,937	211,298	409,684	5,155,707	27,980
2370 - Com-Large Diesel Govt-Muni	204	125,985	277,655	20,526	66,438	490,605	2,076
2380 - Com-Large Diesel Govt-Federal	457	376,707	656,512	117,142	233,511	1,383,872	6,701
2460 - Com-Old Crow Diesel Non-Govt	264	296,115	328,430	1,824	0	626,369	2,803
2480 - Com-Old Crow Diesel Govt-Fed	239	127,785	125,696	1,007	0	254,488	1,677
Total - Commercial		**41,070,903**	**56,720,623**	**7,801,081**	**55,971,771**	**161,564,378**	**682,353**

2013 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,279,950	$13,453,436	$3,469,778	$489,150		$17,412,364		$19,692,314
1180 - Res-Hydro Govt	$38,528	$209,237	$58,435	$6,129		$273,801		$312,330
1260 - Res-Small Diesel Non-Govt	$26,824	$117,448	$18,777	$1,142		$137,367		$164,191
1280 - Res-Small Diesel Govt	$3,768	$27,770	$7,702	$390		$35,862		$39,630
1360 - Res-Large Diesel Non-Govt	$117,522	$623,378	$115,483	$8,312		$747,173		$864,695
1380 - Res-Large Diesel Govt	$7,536	$36,031	$5,087	$447		$41,565		$49,101
1460 - Res-Old Crow Diesel Non-Govt	$23,557	$109,078	$8,094	$5,019		$122,191		$145,748
1480 - Res-Old Crow Diesel Govt	$2,216	$11,749	$4,279	$7,679		$23,707		$25,924
Total - Residential	**2,499,902**	**14,588,128**	**3,687,635**	**518,267**		**18,794,030**		**$21,293,933**
2160 - Com-Hydro Non-Govt		$2,962,236	$4,578,715	$627,004	$2,884,374	$11,052,329	$3,071,403	$14,123,732
2170 - Com-Hydro Govt-Muni		$180,745	$479,886	$105,776	$867,223	$1,633,630	$381,723	$2,015,353
2180 - Com-Hydro Govt-Fed		$735,074	$1,944,375	$554,525	$3,355,067	$6,589,041	$2,000,998	$8,590,038
2260 - Com-Small Diesel Non-govt		$70,623	$71,731	$431	$56	$142,841	$52,571	$195,412
2280 - Com-Small Diesel Govt-Fed		$57,410	$40,968	$114	$0	$98,492	$51,476	$149,969
2360 - Com-Large Diesel Non-Govt		$226,979	$291,724	$33,131	$52,685	$604,520	$206,772	$811,291
2370 - Com-Large Diesel Govt-Muni		$12,599	$35,762	$3,219	$8,544	$60,123	$15,341	$75,464
2380 - Com-Large Diesel Govt-Federal		$52,023	$98,477	$23,428	$30,030	$203,958	$82,484	$286,442
2460 - Com-Old Crow Diesel Non-Govt		$29,611	$42,302	$286	$0	$72,199	$20,714	$92,914
2480 - Com-Old Crow Diesel Govt-Fed		$17,647	$18,854	$201	$0	$36,703	$20,645	$57,348
Total - Commercial	**$0**	**$4,344,948**	**$7,602,794**	**$1,348,115**	**$7,197,978**	**$20,493,836**	**$5,904,127**	**$26,397,963**

RESIDENTIAL AND COMMERCIAL 2014 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2014 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	158,294	112,706,361	27,524,409	3,563,289		143,794,058	
1180 - Res-Hydro Govt	2,122	1,294,093	338,704	32,972		1,665,769	
1260 - Res-Small Diesel Non-Govt	1,864	985,465	148,308	8,111		1,141,885	
1280 - Res-Small Diesel Govt	204	170,831	44,713	2,306		217,850	
1360 - Res-Large Diesel Non-Govt	8,160	5,227,400	912,013	59,836		6,199,250	
1380 - Res-Large Diesel Govt	414	222,660	29,462	2,354		254,477	
1460 - Res-Old Crow Diesel Non-Govt	1,630	909,581	65,258	16,688		991,527	
1480 - Res-Old Crow Diesel Govt	120	72,256	24,803	18,887		115,946	
Total - Residential		**121,588,648**	**29,087,671**	**3,704,443**		**154,380,761**	
2160 - Com-Hydro Non-Govt	23,879	30,250,205	36,303,740	4,083,213	22,903,197	93,540,355	427,938
2170 - Com-Hydro Govt-Muni	2,152	1,845,818	3,804,913	688,962	6,885,943	13,225,636	52,737
2180 - Com-Hydro Govt-Fed	4,652	5,435,232	13,237,909	2,831,732	26,644,165	48,149,038	166,342
2260 - Com-Small Diesel Non-govt	659	717,508	565,815	2,796	371	1,286,489	7,228
2280 - Com-Small Diesel Govt-Fed	545	422,152	277,323	576	0	700,051	4,247
2360 - Com-Large Diesel Non-Govt	1,782	2,356,146	2,352,142	219,486	425,005	5,352,778	29,037
2370 - Com-Large Diesel Govt-Muni	204	130,811	288,660	21,513	69,369	510,354	2,153
2380 - Com-Large Diesel Govt-Federal	461	390,849	681,749	121,684	243,074	1,437,355	7,741
2460 - Com-Old Crow Diesel Non-Govt	264	300,198	332,957	1,850	0	635,005	2,842
2480 - Com-Old Crow Diesel Govt-Fed	240	129,549	127,428	1,021	0	257,997	1,700
Total - Commercial		**41,978,466**	**57,972,634**	**7,972,834**	**57,171,124**	**165,095,058**	**701,964**

2014 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,319,007	$13,682,552	$3,528,629	$498,504		$17,709,686		$20,028,693
1180 - Res-Hydro Govt	$39,193	$213,137	$59,172	$6,215		$278,524		$317,717
1260 - Res-Small Diesel Non-Govt	$27,308	$119,635	$19,013	$1,135		$139,783		$167,091
1280 - Res-Small Diesel Govt	$3,768	$28,136	$7,811	$435		$36,382		$40,150
1360 - Res-Large Diesel Non-Govt	$119,544	$634,606	$116,920	$8,371		$759,898		$879,442
1380 - Res-Large Diesel Govt	$7,647	$36,672	$5,147	$444		$42,263		$49,910
1460 - Res-Old Crow Diesel Non-Govt	$23,880	$110,423	$8,366	$5,135		$123,924		$147,804
1480 - Res-Old Crow Diesel Govt	$2,216	$11,901	$4,333	$7,828		$24,062		$26,279
Total - Residential	**2,542,562**	**14,837,063**	**3,749,392**	**528,067**		**19,114,521**		**$21,657,084**
2160 - Com-Hydro Non-Govt		$3,025,020	$4,675,922	$640,248	$2,945,351	$11,286,541	$3,162,461	$14,449,002
2170 - Com-Hydro Govt-Muni		$184,582	$490,073	$108,029	$885,532	$1,668,216	$389,726	$2,057,943
2180 - Com-Hydro Govt-Fed		$750,606	$1,985,686	$566,346	$3,426,440	$6,729,078	$2,047,667	$8,776,745
2260 - Com-Small Diesel Non-govt		$71,751	$72,877	$438	$56	$145,123	$53,411	$198,534
2280 - Com-Small Diesel Govt-Fed		$58,299	$41,598	$115	$0	$100,013	$52,276	$152,289
2360 - Com-Large Diesel Non-Govt		$235,615	$302,956	$34,415	$54,656	$627,641	$214,584	$842,226
2370 - Com-Large Diesel Govt-Muni		$13,081	$37,179	$3,373	$8,921	$62,555	$15,913	$78,467
2380 - Com-Large Diesel Govt-Federal		$53,976	$102,262	$24,337	$31,259	$211,835	$95,292	$307,127
2460 - Com-Old Crow Diesel Non-Govt		$30,020	$42,885	$290	$0	$73,195	$21,001	$94,195
2480 - Com-Old Crow Diesel Govt-Fed		$17,891	$19,114	$204	$0	$37,209	$20,930	$58,139
Total - Commercial	**$0**	**$4,440,840**	**$7,770,553**	**$1,377,797**	**$7,352,215**	**$20,941,405**	**$6,073,262**	**$27,014,666**

RESIDENTIAL AND COMMERCIAL 2015 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2015 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	160,997	114,633,102	27,994,941	3,624,202		146,252,245	
1180 - Res-Hydro Govt	2,158	1,316,359	344,534	33,540		1,694,433	
1260 - Res-Small Diesel Non-Govt	1,896	1,002,560	150,882	8,251		1,161,693	
1280 - Res-Small Diesel Govt	213	173,250	45,344	2,340		220,933	
1360 - Res-Large Diesel Non-Govt	8,303	5,318,936	928,005	60,887		6,307,828	
1380 - Res-Large Diesel Govt	420	226,540	29,976	2,396		258,912	
1460 - Res-Old Crow Diesel Non-Govt	1,659	925,182	66,379	16,974		1,008,536	
1480 - Res-Old Crow Diesel Govt	120	73,495	25,229	19,211		117,935	
Total - Residential		**123,669,424**	**29,585,289**	**3,767,800**		**157,022,514**	
2160 - Com-Hydro Non-Govt	24,258	30,893,773	37,075,522	4,170,087	23,392,338	95,531,720	438,917
2170 - Com-Hydro Govt-Muni	2,185	1,885,031	3,885,913	703,601	7,032,065	13,506,610	54,053
2180 - Com-Hydro Govt-Fed	4,723	5,551,590	13,520,338	2,892,006	27,212,458	49,176,392	170,511
2260 - Com-Small Diesel Non-govt	670	729,787	575,504	2,844	377	1,308,511	7,351
2280 - Com-Small Diesel Govt-Fed	553	429,167	281,926	586	0	711,678	4,317
2360 - Com-Large Diesel Non-Govt	1,811	2,390,960	2,386,893	222,723	431,278	5,431,854	29,466
2370 - Com-Large Diesel Govt-Muni	205	132,685	292,795	21,822	70,367	517,669	2,184
2380 - Com-Large Diesel Govt-Federal	468	396,476	691,565	123,434	246,578	1,458,053	7,829
2460 - Com-Old Crow Diesel Non-Govt	264	304,573	337,809	1,877	0	644,259	2,883
2480 - Com-Old Crow Diesel Govt-Fed	240	131,437	129,285	1,036	0	261,757	1,725
Total - Commercial		**42,845,478**	**59,177,550**	**8,140,016**	**58,385,460**	**168,548,504**	**719,237**

2015 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,358,606	$13,916,459	$3,588,951	$507,026		$18,012,436		$20,371,042
1180 - Res-Hydro Govt	$39,858	$216,804	$60,190	$6,322		$283,317		$323,175
1260 - Res-Small Diesel Non-Govt	$27,776	$121,711	$19,343	$1,154		$142,208		$169,985
1280 - Res-Small Diesel Govt	$3,934	$28,534	$7,922	$441		$36,897		$40,831
1360 - Res-Large Diesel Non-Govt	$121,639	$645,719	$118,970	$8,518		$773,207		$894,846
1380 - Res-Large Diesel Govt	$7,757	$37,311	$5,237	$452		$43,000		$50,757
1460 - Res-Old Crow Diesel Non-Govt	$24,304	$112,317	$8,510	$5,223		$126,050		$150,354
1480 - Res-Old Crow Diesel Govt	$2,216	$12,105	$4,407	$7,963		$24,475		$26,691
Total - Residential	**2,586,092**	**15,090,960**	**3,813,530**	**537,099**		**19,441,589**		**$22,027,681**
2160 - Com-Hydro Non-Govt		$3,089,377	$4,775,327	$653,870	$3,008,255	$11,526,829	$3,243,594	$14,770,423
2170 - Com-Hydro Govt-Muni		$188,503	$500,506	$110,325	$904,324	$1,703,657	$399,455	$2,103,112
2180 - Com-Hydro Govt-Fed		$766,675	$2,028,051	$578,401	$3,499,522	$6,872,649	$2,098,987	$8,971,635
2260 - Com-Small Diesel Non-govt		$72,979	$74,125	$446	$57	$147,607	$54,326	$201,932
2280 - Com-Small Diesel Govt-Fed		$59,268	$42,289	$117	$0	$101,674	$53,145	$154,819
2360 - Com-Large Diesel Non-Govt		$239,096	$307,432	$34,923	$55,462	$636,913	$217,755	$854,669
2370 - Com-Large Diesel Govt-Muni		$13,269	$37,712	$3,422	$9,049	$63,451	$16,141	$79,592
2380 - Com-Large Diesel Govt-Federal		$54,753	$103,735	$24,687	$31,710	$214,885	$96,375	$311,260
2460 - Com-Old Crow Diesel Non-Govt		$30,457	$43,510	$294	$0	$74,261	$21,307	$95,568
2480 - Com-Old Crow Diesel Govt-Fed		$18,151	$19,393	$207	$0	$37,751	$21,235	$58,986
Total - Commercial	**$0**	**$4,532,528**	**$7,932,078**	**$1,406,692**	**$7,508,379**	**$21,379,677**	**$6,222,320**	**$27,601,997**

INDUSTRIAL 2013, 2014 and 2015 RATES, BILLING DETERMINANTS & REVENUE ON EXISTING RATES

Industrial Rate	Demand Charge per kVA	Energy $/kWh Block 1	kVA Total Billing Demand	kWh Energy	Demand Revenue	Energy Revenue	Total Revenue
2013 - 39 - Industrial Primary	$15.94	$0.0808	3,750	1,024,800	$59,775	$82,804	$142,579
2014 - 39 - Industrial Primary	$15.94	$0.0808	15,000	4,620,000	$239,100	$373,296	$612,396
2015 - 39 - Industrial Primary	$15.94	$0.0808	15,000	4,620,000	$239,100	$373,296	$612,396

LIGHTING 2013, 2014 and 2015 RATES, BILLING DETERMINANTS & REVENUE ON EXISTING RATES

Street Lights Rates	Watts	Mthly Customer Charge	Mthly Demand Charge per Watt	# Cust Billed in 2013	# Cust Billed in 2014	# Cust Billed in 2015	Street Light Revenue 2013	Street Light Revenue 2014	Street Light Revenue 2015
6110 - Mercury Vapor	175	$7.83	$0.0496	0	0	0	$0	$0	$0
6120 - Mercury Vapor	250	$7.83	$0.0496	264	264	264	$5,341	$5,341	$5,341
6130 - Mercury Vapor	400	$7.83	$0.0496	0	0	0	$0	$0	$0
6140 - High Pressure Sodium	100	$7.83	$0.0496	38,564	38,696	38,828	$493,234	$494,922	$496,610
6180 - High Pressure Sodium	250	$7.83	$0.0496	14,920	15,364	15,808	$301,832	$310,814	$319,796
6190 - High Pressure Sodium	400	$7.83	$0.0496	252	252	252	$6,973	$6,973	$6,973
6360 - High Pressure Sodium	150	$7.83	$0.0496	4,488	4,704	4,920	$68,532	$71,830	$75,128
6580 - High Pressure Sodium-High Mast	250	$9.10	$0.0496	1,260	1,260	1,260	$27,090	$27,090	$27,090
6590 - High Pressure Sodium-High Mast	400	$9.10	$0.0496	636	636	636	$18,406	$18,406	$18,406
6640 - High Pressure Sodium	70	$7.83	$0.0496	1,244	1,304	1,364	$14,057	$14,735	$15,413
6720 - Mercury Vapor Energy Only	250	$19.05	$0.000	384	384	384	$7,315	$7,315	$7,315
6780 - High Pressure Sodium Energy Only	250	$19.05	$0.000	180	180	180	$3,429	$3,429	$3,429
6790 - High Pressure Sodium Energy Only	400	$29.13	$0.000	180	180	180	$5,243	$5,243	$5,243
Total							$951,451	$966,098	$980,745

Private Lights Rates	Watts	Mthly Customer Charge	# Cust Billed in 2013	# Cust Billed in 2014	# Cust Billed in 2015	Street Light Revenue 2013	Street Light Revenue 2014	Street Light Revenue 2015
7100 - Mercury Vapor - Regular	175	$17.46	1,440	1,368	1,296	$25,142	$23,885	$22,628
7120 - Mercury Vapor - E&M	175	$12.15	0	0	0	$0	$0	$0
7130 - Mercury Vapor - Metered	175	$9.81	92	80	68	$903	$785	$667
7200 - High Pressure Sodium - Regular	250	$21.35	36	36	36	$769	$769	$769
7300 - Mercury Vapor - Regular	400	$28.36	0	0	0	$0	$0	$0
7400 - Mercury Vapor Flood - Regular	400	$31.32	708	672	636	$22,175	$21,047	$19,920
7420 - Mercury Vapor Flood - E&M	400	$21.85	36	36	36	$787	$787	$787
7430 - Mercury Vapor Flood - Metered	400	$12.63	36	36	36	$455	$455	$455
7500 - High Pressure Sodium - Regular	100	$14.33	4,532	4,520	4,508	$64,944	$64,772	$64,600
7520 - High Pressure Sodium - E&M	100	$7.95	3,684	3,720	3,756	$29,288	$29,574	$29,860
7530 - High Pressure Sodium - Metered	100	$9.04	96	96	96	$868	$868	$868
Total						$145,329	$142,940	$140,552

YEC ESTIMATED REVENUE FOR 2013-2015

2013

					11.87%	8.19%	
SALES				**Sales ($)**	**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh			1,815,000.00	215,440.50		2,030,440.50
General Service	kWh			3,735,000.00	443,344.50		4,178,344.50
Industrial	kWh			4,787,000.00		392,055.30	5,179,055.30
Streetlights	kWh			88,000.00	10,445.60		98,445.60
Space	kWh			4,000.00	474.80		4,474.80
				10,429,000.00	669,705.40		11,490,760.70

2014

					11.87%	**8.19%**	
SALES		**2014**			**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh	13,261,660	14.63	1,940,180.86	230,299.47		2,170,480.33
General Service	kWh	22,750,253	16.51	3,756,066.77	445,845.13		4,201,911.90
Industrial	kWh	54,070,520	11.79	6,374,914.31		522,105.48	6,897,019.79
Streetlights	kWh	297,460	31.55	93,848.63	11,139.83		104,988.46
Space	kWh	15,000	26.76	4,014.00	476.46		4,490.46
				12,169,024.57	687,760.89		13,378,890.94

2015

					11.87%	**8.19%**	
SALES		**2015**			**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh	13,305,048	14.63	1,946,528.52	231,052.94		2,177,581.46
General Service	kWh	22,815,497	16.51	3,766,838.55	447,123.74		4,213,962.29
Industrial	kWh	55,070,520	11.79	6,492,814.31		531,761.49	7,024,575.80
Streetlights	kWh	297,647	31.55	93,907.63	11,146.84		105,054.46
Space	kWh	15,000	26.76	4,014.00	476.46		4,490.46
				12,304,103.01	689,799.97		13,525,664.47

YEC-YECL-8

Reference: Section 3 – Purchase Power – Generation and Purchased Power forecast

Request:

(a) Please provide details of requested Purchase Power Flow Through deferral account, including:

(i) Please confirm the balance of this account is zero.

(ii) Please confirm that the Purchase Power Flow Through deferral account requires a collection mechanism to be implemented and approval by the YUB prior to collecting or refunding any balances.

(iii) Please provide any updates regarding the status of any future collection mechanism to be proposed by YECL.

Response:

(a) (i) Yukon Electrical is able to confirm the balance was zero at least with respect to what it knew as of December 31, 2012. It is presently unclear as to whether a final Board decision on Wholesale Rate Schedule 42 and the associated Energy Reconciliation Adjustment (ERA) will, or will not, result in a deferral balance as of December 31, 2012 and for periods thereafter.

(ii) Confirmed.

(iii) There is no update regarding the status of any future collection mechanism.

YEC-YECL-10

Reference: Defined Benefit Deferral Account

Request:

(a) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(b) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) Not confirmed in the context of this GRA as compared to the 2008-2009 GRA. When Yukon Electrical filed its last GRA in 2008, Federal pension regulations in place at that time required updated actuarial valuations to be completed for defined benefit ("DB") pension plans once every three years. An actuarial valuation for the DB plan that Yukon Electrical participates in was completed as at December 31, 2006 to determine the required funding for the years 2007-2009. The level of the required contributions was known for the three year period 2007-2009 which, in turn, covered the test period 2008-2009.

In 2010, regulations amending certain Federal pension regulations came into force. As a result, Federally-regulated pension plans, such as the plan in which Yukon Electrical participates, are now generally required to file updated actuarial valuation reports on an annual basis. As the valuation reports determine the required funding for the next year, this means that Yukon Electrical's required contributions will fluctuate on a yearly basis throughout the 2013-2015 test period. The required contributions can both increase or decrease depending on market conditions and the performance of the pension plan assets in any year. That means that there is forecast risk for both Yukon Electrical (in the case of an increase in required contributions over the amounts included in Yukon Electrical's revenue requirement) and the ratepayer (in the case of a decrease in required contributions over the amounts included in Yukon Electrical's revenue requirement) if a deferral account is not approved. To provide further context for the need for this deferral, Yukon Electrical's contributions between 2006 and 2012 have varied between a low of $0 per year and a high of $1,268,000 per year.

(b) Yukon Electrical has not completed an exhaustive search of other utilities in Canada with similar deferral accounts. Yukon Electrical is, however, able to advise that both Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited have similar deferral accounts approved that cover all increases or decreases to required cash contributions to the defined benefit pension plan as compared to forecast.

YEC-YECL-11

Reference: Section 7 – Depreciation – Depreciation Expense

Request:

(a) Please reconcile the depreciation rates on schedules 7.2 -7.4 to the Depreciation Study results performed by Gannett Fleming. Please explain if any difference.

(b) Please provide a comparison by account of the proposed depreciation rates to the last approved depreciation rates.

(c) Please provide schedules using YECL's last approved depreciation rates similar to schedules 7.2-7.4.

(d) Please identify the amounts included as expense in the 2013-15 GRA revenue requirements with respect to net salvage costs. Indicate under which account or category these forecast expenses are included.

Response:

(a) The Depreciation Study results performed by Gannett Fleming and provided in Section 7, Attachment 1 are based on its depreciation analysis as of December 31, 2011. The results of Gannett Fleming's 2011 study produced depreciation parameters of Iowa Curve, average service life, and net salvage percentage. To more accurately reflect the actual depreciation rates that will be used for actual 2013-2015 data, Yukon Electrical has applied Gannett Fleming's recommended depreciation parameters to Yukon Electrical's forecast year end balances.

(b) The YUB approves depreciation parameters of Iowa Curve, Average Service Life and Net Salvage Percentages. The depreciation rates are the result of the application of these recommended depreciation parameters to forecast balances. Please refer to YEC-YECL-11(b) Attachments 1 to 3 for a comparison of 2013-2015 depreciation rates using the depreciation parameters approved in the 2008/2009 GRA to the forecast depreciation parameters for the 2013-2015 GRA.

(c) Please refer to YUB-YECL-83(a) Attachment 1.

(d) There are no net salvage costs included in expense. Please refer to the following for the Net Salvage costs included as part of the Reserve for site restoration (per YEC-YECL-12(b) Attachment 1).

Costs of Removal	49	50	185	100	64
Gross Salvage	(74)	(14)	(68)	(38)	(10)
Schedule 8.6 Line 22	(25)	36	117	62	54

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.33%	2.40%
42300	Reservoirs, Dams & Waterways	3.57%	2.40%
42500	Generators	3.76%	2.68%
42600	Accessory Equipment	3.24%	2.58%
42700	Misc Plant Equipment	3.70%	4.07%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	3.02%	3.50%
44401	Fuel Holders, Producers & Acc. Equipme	2.96%	3.56%
44501	Generating Equipment & Primer Movers ·	3.31%	3.82%
44601	Accessory Electric Equipment - Other	2.98%	2.99%
44701	Misc Power Plant Equipment - Other	3.16%	2.84%
	Carmacks		
44202	Structures and Improvement - Other	2.75%	3.09%
44402	Fuel Holders, Producers & Acc. Equipme	2.98%	3.60%
44502	Generating Equipment & Primer Movers ·	3.30%	3.80%
44602	Accessory Electric Equipment - Other	3.03%	3.03%
44702	Misc Power Plant Equipment - Other	3.21%	2.93%
	Destruction Bay		
44203	Structures and Improvement - Other	2.22%	3.03%
44403	Fuel Holders, Producers & Acc. Equipme	2.97%	5.30%
44503	Generating Equipment & Primer Movers ·	4.09%	7.05%
44603	Accessory Electric Equipment - Other	2.98%	4.77%
44703	Misc Power Plant Equipment - Other	2.97%	4.82%
	Haines Junction		
44204	Structures and Improvement - Other	2.83%	3.21%
44404	Fuel Holders, Producers & Acc. Equipme	3.02%	3.62%
44504	Generating Equipment & Primer Movers ·	3.61%	4.24%
44604	Accessory Electric Equipment - Other	2.80%	2.80%
44704	Misc Power Plant Equipment - Other	2.89%	2.63%
	Old Crow		
44205	Structures and Improvement - Other	2.51%	2.79%
44405	Fuel Holders, Producers & Acc. Equipme	2.99%	3.60%
44505	Generating Equipment & Primer Movers ·	3.74%	4.22%
44605	Accessory Electric Equipment - Other	2.79%	2.79%
44705	Misc Power Plant Equipment - Other	2.88%	2.58%

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.26%	2.57%
44406	Fuel Holders, Producers & Acc. Equipme	2.66%	3.56%
44506	Generating Equipment & Primer Movers ·	3.41%	3.97%
44606	Accessory Electric Equipment - Other	3.07%	3.81%
44706	Misc Power Plant Equipment - Other	3.04%	3.57%
	Ross River		
44207	Structures and Improvement - Other	2.85%	3.25%
44407	Fuel Holders, Producers & Acc. Equipme	2.98%	3.57%
44507	Generating Equipment & Primer Movers ·	3.27%	3.71%
44607	Accessory Electric Equipment - Other	3.01%	3.01%
44707	Misc Power Plant Equipment - Other	3.12%	2.81%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.75%	3.08%
44408	Fuel Holders, Producers & Acc. Equipme	2.99%	3.59%
44508	Generating Equipment & Primer Movers ·	2.69%	3.01%
44608	Accessory Electric Equipment - Other	2.87%	2.87%
44708	Misc Power Plant Equipment - Other	3.24%	2.97%
	Swift River		
44209	Structures and Improvement - Other	2.54%	2.80%
44409	Fuel Holders, Producers & Acc. Equipme	2.94%	3.53%
44509	Generating Equipment & Primer Movers ·	4.04%	4.47%
44609	Accessory Electric Equipment - Other	3.00%	3.01%
44709	Misc Power Plant Equipment - Other	3.10%	2.78%
	Teslin		
44210	Structures and Improvement - Other	2.98%	3.44%
44410	Fuel Holders, Producers & Acc. Equipme	3.01%	3.63%
44510	Generating Equipment & Primer Movers ·	3.39%	3.94%
44610	Accessory Electric Equipment - Other	3.11%	3.14%
44710	Misc Power Plant Equipment - Other	3.18%	2.86%
	Watson Lake		
44211	Structures and Improvement - Other	2.42%	2.66%
44411	Fuel Holders, Producers & Acc. Equipme	3.00%	3.60%
44511	Generating Equipment & Primer Movers ·	3.60%	4.04%
44611	Accessory Electric Equipment - Other	2.81%	2.81%
44711	Misc Power Plant Equipment - Other	3.12%	2.76%
	Mobiles		
44299	Structures and Improvement - Other	3.18%	3.52%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers ·	3.77%	4.23%
44699	Accessory Electric Equipment - Other	3.13%	3.13%
44799	Misc Power Plant Equipment - Other	3.26%	2.86%
Sub Transmission			
45700	Substation Equipment	2.49%	2.25%

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Distribution			
47100	Land Rigths	1.51%	1.51%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.59%	2.57%
47500	Underground Conduit	2.41%	3.61%
47510	Underground Services	2.10%	2.87%
47610	Meters	4.10%	7.65%
47630	Automatic Meter Reading	4.52%	7.31%
47710	Substation Equipment	2.77%	2.75%
47810	Street Lights & Signal Systems	3.98%	3.77%
47820	Sentinel Lights	2.99%	2.99%
47910	Line Transformers	3.03%	2.66%
General Plant			
48200	Structures and Improvements	3.10%	2.63%
48300	Office Furniture and Equipment	5.70%	5.70%
48320	Computer Equipment and Accessories	18.73%	18.73%
48400	Transportation Equipment - Category 1	9.34%	6.44%
48500	Tools and Instruments	6.33%	6.33%
48600	Communication Equipment	5.50%	5.50%
48820	Houses	2.66%	2.93%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.54%	2.79%
42300	Reservoirs, Dams & Waterways	3.68%	2.60%
42500	Generators	3.79%	2.77%
42600	Accessory Equipment	3.49%	2.87%
42700	Misc Plant Equipment	4.06%	4.46%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	3.01%	3.52%
44401	Fuel Holders, Producers & Acc. Equipme	2.98%	3.59%
44501	Generating Equipment & Primer Movers -	3.97%	4.22%
44601	Accessory Electric Equipment - Other	3.07%	3.10%
44701	Misc Power Plant Equipment - Other	3.19%	2.92%
	Carmacks		
44202	Structures and Improvement - Other	2.72%	3.06%
44402	Fuel Holders, Producers & Acc. Equipme	2.98%	3.59%
44502	Generating Equipment & Primer Movers -	3.25%	3.72%
44602	Accessory Electric Equipment - Other	3.01%	3.01%
44702	Misc Power Plant Equipment - Other	3.18%	2.90%
	Destruction Bay		
44203	Structures and Improvement - Other	2.44%	4.84%
44403	Fuel Holders, Producers & Acc. Equipme	2.98%	6.70%
44503	Generating Equipment & Primer Movers -	4.00%	7.03%
44603	Accessory Electric Equipment - Other	3.04%	5.87%
44703	Misc Power Plant Equipment - Other	3.03%	5.88%
	Haines Junction		
44204	Structures and Improvement - Other	2.80%	3.17%
44404	Fuel Holders, Producers & Acc. Equipme	3.02%	3.62%
44504	Generating Equipment & Primer Movers -	3.56%	4.17%
44604	Accessory Electric Equipment - Other	2.77%	2.77%
44704	Misc Power Plant Equipment - Other	2.86%	2.61%
	Old Crow		
44205	Structures and Improvement - Other	2.61%	2.94%
44405	Fuel Holders, Producers & Acc. Equipme	2.99%	3.60%
44505	Generating Equipment & Primer Movers -	3.67%	4.17%
44605	Accessory Electric Equipment - Other	2.86%	2.87%
44705	Misc Power Plant Equipment - Other	2.94%	2.66%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.23%	2.54%
44406	Fuel Holders, Producers & Acc. Equipme	2.64%	3.54%
44506	Generating Equipment & Primer Movers -	3.36%	3.91%
44606	Accessory Electric Equipment - Other	3.05%	3.78%
44706	Misc Power Plant Equipment - Other	3.02%	3.55%
	Ross River		
44207	Structures and Improvement - Other	2.80%	3.19%
44407	Fuel Holders, Producers & Acc. Equipme	2.97%	3.56%
44507	Generating Equipment & Primer Movers -	3.24%	3.65%
44607	Accessory Electric Equipment - Other	2.99%	2.99%
44707	Misc Power Plant Equipment - Other	3.10%	2.80%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.73%	3.07%
44408	Fuel Holders, Producers & Acc. Equipme	2.99%	3.59%
44508	Generating Equipment & Primer Movers -	2.64%	2.95%
44608	Accessory Electric Equipment - Other	2.85%	2.85%
44708	Misc Power Plant Equipment - Other	3.21%	2.95%
	Swift River		
44209	Structures and Improvement - Other	2.51%	2.78%
44409	Fuel Holders, Producers & Acc. Equipme	2.93%	3.51%
44509	Generating Equipment & Primer Movers -	4.04%	4.46%
44609	Accessory Electric Equipment - Other	2.98%	2.99%
44709	Misc Power Plant Equipment - Other	3.08%	2.77%
	Teslin		
44210	Structures and Improvement - Other	2.90%	3.36%
44410	Fuel Holders, Producers & Acc. Equipme	3.01%	3.62%
44510	Generating Equipment & Primer Movers -	3.33%	3.86%
44610	Accessory Electric Equipment - Other	3.07%	3.11%
44710	Misc Power Plant Equipment - Other	3.16%	2.85%
	Watson Lake		
44211	Structures and Improvement - Other	2.54%	2.79%
44411	Fuel Holders, Producers & Acc. Equipme	3.01%	3.61%
44511	Generating Equipment & Primer Movers -	4.00%	4.27%
44611	Accessory Electric Equipment - Other	2.87%	2.87%
44711	Misc Power Plant Equipment - Other	3.14%	2.77%
	Mobiles		
44299	Structures and Improvement - Other	3.10%	3.40%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers -	4.36%	4.52%
44699	Accessory Electric Equipment - Other	3.10%	3.10%
44799	Misc Power Plant Equipment - Other	3.23%	2.83%
Sub Transmission			
45700	Substation Equipment	2.48%	2.25%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Distribution			
47100	Land Rigths	1.50%	1.50%
47200	Demand Side Management	10.00%	10.00%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.59%	2.58%
47500	Underground Conduit	2.40%	3.61%
47510	Underground Services	2.10%	2.86%
47610	Meters	4.11%	8.09%
47630	Automatic Meter Reading	4.50%	7.13%
47710	Substation Equipment	2.79%	2.75%
47810	Street Lights & Signal Systems	3.96%	3.75%
47820	Sentinel Lights	2.93%	2.93%
47910	Line Transformers	3.03%	2.65%
General Plant			
48200	Structures and Improvements	3.14%	2.67%
48300	Office Furniture and Equipment	6.67%	6.67%
48320	Computer Equipment and Accessories	20.00%	20.00%
48400	Transportation Equipment - Category 1	9.50%	6.59%
48500	Tools and Instruments	6.67%	6.67%
48600	Communication Equipment	6.67%	6.67%
48820	Houses	2.65%	2.91%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.61%	2.91%
42300	Reservoirs, Dams & Waterways	3.71%	2.68%
42500	Generators	3.79%	2.82%
42600	Accessory Equipment	3.57%	2.97%
42700	Misc Plant Equipment	4.10%	4.51%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	2.94%	3.43%
44401	Fuel Holders, Producers & Acc. Equipme	2.97%	3.58%
44501	Generating Equipment & Primer Movers -	4.09%	4.33%
44601	Accessory Electric Equipment - Other	3.04%	3.07%
44701	Misc Power Plant Equipment - Other	3.17%	2.89%
	Carmacks		
44202	Structures and Improvement - Other	2.69%	3.03%
44402	Fuel Holders, Producers & Acc. Equipme	2.96%	3.58%
44502	Generating Equipment & Primer Movers -	3.19%	3.65%
44602	Accessory Electric Equipment - Other	2.99%	2.99%
44702	Misc Power Plant Equipment - Other	3.16%	2.88%
	Destruction Bay		
44203	Structures and Improvement - Other	2.64%	6.94%
44403	Fuel Holders, Producers & Acc. Equipme	2.99%	8.52%
44503	Generating Equipment & Primer Movers -	4.33%	9.53%
44603	Accessory Electric Equipment - Other	3.10%	7.32%
44703	Misc Power Plant Equipment - Other	3.10%	7.33%
	Haines Junction		
44204	Structures and Improvement - Other	2.76%	3.14%
44404	Fuel Holders, Producers & Acc. Equipme	3.01%	3.62%
44504	Generating Equipment & Primer Movers -	3.51%	4.11%
44604	Accessory Electric Equipment - Other	2.75%	2.75%
44704	Misc Power Plant Equipment - Other	2.84%	2.59%
	Old Crow		
44205	Structures and Improvement - Other	2.90%	3.38%
44405	Fuel Holders, Producers & Acc. Equipme	3.01%	3.65%
44505	Generating Equipment & Primer Movers -	4.06%	4.35%
44605	Accessory Electric Equipment - Other	3.09%	3.15%
44705	Misc Power Plant Equipment - Other	3.13%	2.90%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.21%	2.51%
44406	Fuel Holders, Producers & Acc. Equipme	2.62%	3.52%
44506	Generating Equipment & Primer Movers -	3.31%	3.84%
44606	Accessory Electric Equipment - Other	3.02%	3.76%
44706	Misc Power Plant Equipment - Other	2.99%	3.53%
	Ross River		
44207	Structures and Improvement - Other	2.78%	3.19%
44407	Fuel Holders, Producers & Acc. Equipme	2.96%	3.56%
44507	Generating Equipment & Primer Movers -	3.27%	3.65%
44607	Accessory Electric Equipment - Other	2.98%	2.99%
44707	Misc Power Plant Equipment - Other	3.10%	2.81%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.84%	3.24%
44408	Fuel Holders, Producers & Acc. Equipme	3.00%	3.61%
44508	Generating Equipment & Primer Movers -	3.13%	3.36%
44608	Accessory Electric Equipment - Other	2.95%	2.98%
44708	Misc Power Plant Equipment - Other	3.22%	2.98%
	Swift River		
44209	Structures and Improvement - Other	2.49%	2.76%
44409	Fuel Holders, Producers & Acc. Equipme	2.92%	3.50%
44509	Generating Equipment & Primer Movers -	3.96%	4.43%
44609	Accessory Electric Equipment - Other	2.95%	2.96%
44709	Misc Power Plant Equipment - Other	3.06%	2.75%
	Teslin		
44210	Structures and Improvement - Other	2.84%	3.29%
44410	Fuel Holders, Producers & Acc. Equipme	3.00%	3.61%
44510	Generating Equipment & Primer Movers -	3.29%	3.78%
44610	Accessory Electric Equipment - Other	3.05%	3.08%
44710	Misc Power Plant Equipment - Other	3.14%	2.83%
	Watson Lake		
44211	Structures and Improvement - Other	2.65%	2.91%
44411	Fuel Holders, Producers & Acc. Equipme	3.01%	3.61%
44511	Generating Equipment & Primer Movers -	3.93%	4.26%
44611	Accessory Electric Equipment - Other	2.95%	2.95%
44711	Misc Power Plant Equipment - Other	3.16%	2.78%
	Mobiles		
44299	Structures and Improvement - Other	3.02%	3.32%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers -	4.22%	4.50%
44699	Accessory Electric Equipment - Other	3.08%	3.08%
44799	Misc Power Plant Equipment - Other	3.20%	2.81%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Sub Transmission			
45700	Substation Equipment	2.47%	2.24%
Distribution			
47100	Land Rigths	1.50%	1.50%
47200	Demand Side Management	10.00%	10.00%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.60%	2.58%
47500	Underground Conduit	2.40%	3.61%
47510	Underground Services	2.10%	2.86%
47610	Meters	4.10%	7.40%
47630	Automatic Meter Reading	4.54%	8.08%
47710	Substation Equipment	2.80%	2.75%
47810	Street Lights & Signal Systems	3.97%	3.76%
47820	Sentinel Lights	2.87%	2.87%
47910	Line Transformers	3.03%	2.65%
General Plant			
48200	Structures and Improvements	3.13%	2.66%
48300	Office Furniture and Equipment	6.67%	6.67%
48320	Computer Equipment and Accessories	20.00%	20.00%
48400	Transportation Equipment - Category 1	9.87%	6.98%
48500	Tools and Instruments	6.67%	6.67%
48600	Communication Equipment	6.67%	6.67%
48820	Houses	2.63%	2.89%

YEC-YECL-12

Reference: Section 7 – Depreciation – Depreciation Study

Request:

(a) The YUB ruled in decision 2009-02 that YECL was not entitled to collect a provision for salvage. Please explain what has changed in Yukon that justifies YECL requesting this large increase in depreciation expense.

(b) Please provide a continuity schedule of the reserve for site restoration for each year 2008-2012. For each year, please provide a schedule of individual charges to the Fund and, for each charge, provide the justification for each charge to the fund.

(c) Please provide further detailed explanation regarding how the proposed deferral account to allow the ability to file future applications, as necessary, to change its depreciation parameters within the 2013-2015 test period, and flow through the impact of any such change to customers within the test period would operate. Please provide any illustrative examples.

(d) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) The first issue that has changed since Board Order 2009-02 is that sending the right price signal to customers has taken on added importance as a result of diesel generation once again being on the margin in the Yukon. As Yukon Energy is aware, price signals that reflect the full cost to serve customers were discussed as part of the 2010 Yukon Electrical and Yukon Energy Joint Phase II Rate Application. While a large amount of the rate design discussion centered on economy and efficiency principles within the rate design of runoff rates and what exactly was meant by the term “economy and efficiency”, Yukon Electrical notes the following statements in Board Order 2010-13 (paragraphs 196-197):

> The Board has considered the views of all the Parties and notes that there clearly is no consensus on this issue. However, it is clear that the Companies agree that in the past, economy and efficiency has been linked to the incremental cost of diesel generation.
>
> In terms of pricing signals, the Board is of the view that the best pricing signals to customers are those prices that reflect the full cost to serve those customers. Arguments on incremental cost of diesel generation, or what portion of the incremental cost of diesel generation should be reflected in the runoff rates should take a distant backseat to the proper alignment of costs to revenues for each rate class. Once rebalancing has occurred for the rate classes, then issues relating to runoff can be examined in greater detail.

While the above statements were in the context of runoff rates, it is for this exact reason of prices reflecting the full cost to serve customer that Yukon Electrical is requesting to once again collect negative net salvage as part of its revenue requirement.

A second large change since Board Order 2009-02 has been the development and inclusion in this Application of the Joint Yukon Electrical and Yukon Energy Demand Side Management (DSM) program. As Yukon Energy is aware, this program will promote energy conservation and will result in lower energy consumption. It is Yukon Electrical's position that it is counter intuitive to be investing in this DSM program while, at the same time, not sending the right price signal by not fully charging current customers for the cost to provide electric service; namely the cost associated with net salvage.

A third large change since Board Order 2009-02 has been the cessation of collection of net salvage resulting in Yukon Electrical falling considerably behind in its required recovery of the funds for future removal of assets. In the 3 year period from 2009 through 2011, an increase in the amount of Future Removal and Site Restoration (i.e. FRSR) deficiency transfer from current users of the Yukon Electrical utility assets to future rate-payers of $7.9 million has accrued to a total balance of over $12 million. It is noted that this significant increase in transfer to future rate-payers is caused by two significant forces. Firstly, the retirement costs associated with assets that have retired over the past 3 year

period have drawn down the FRSR by over 6.2%[1] of the balance that existed at December 31, 2008. However, this draw down of the FRSR was caused by retirements of only approximately 3% of the plant in service as at December 2008[2]. In other words, the FRSR balance is drawing down at approximately twice the rate of the asset retirement activity of the plant in service balance that existed at December 31, 2008.

The second cause of the significant increase in the accumulated FRSR deficiency is the fact that older vintages of assets are now 3 years closer to expected retirement, providing less time for these vintages to recover the FRSR deficiency. While approximately 3% of the investment in plant in service as of 2008 has retired over the period from 2009 through 2011, this pace of retirements is expected to significantly increase in future years, which will require significantly increased amounts of cost of removal funding. For example, over the past 16 years, 4 diesel generating units have been removed and retired from service. However, over the next 3 year period 7 units will require replacement due to age and condition. As such, the pace of retirements will significantly increase over the next few years.

Gannett Fleming has advised that the level of accumulated FRSR deficiency will continue to increase at an increasingly rapid pace in future years, if FRSR funding is not re-instated into the deprecation calculations. As noted above there are two independent forces that are causing increases in the amount of the deficiency, that will cause the deficiency to grow at an exponential rate, as witnessed over the past 3 year period. The inter-generational inequity of the current process as mandated by the Board in Decision 2009-02 has already caused future rate-payers to bear $7.9 million of additional burden, and continuation of this practice will see this burden increase by exponential amounts in future years.

The concept of inclusion of net salvage provisions into the depreciation rate calculations has been a topic of debate in many regulatory jurisdictions across Canada since the issuance of the YUB Board Decision 2009-02. As indicated in the Additional Evidence of Larry Edwin Kennedy filed with the current Yukon Electrical Application, this topic has received considerable attention in the

[1] Calculated by comparing the 2008 FRSR balance of $4,688,112 to the 2012 balance of $4.395,151
[2] Based on2009 through 2012 retirement transactions of $3.3 million compared to the 2008 plant in service balance of $115.7 million

depreciation rate filings in many jurisdictions. However, notwithstanding the significant amount of regulatory debate, the inclusion of net salvage percentages in the depreciation rate calculations continues to be widely accepted throughout Canada and North America. Furthermore, the topic of re-instatement of net salvage into depreciation rate calculations has been specifically discussed in hearings in British Columbia in 2011, in which the BCUC specifically allowed FortisBC Energy Inc. to re-instate collection of net salvage as part of their depreciation rate calculations. As stated by the BCUC in FortisBC Energy's 2012-2013 Revenue Requirements and Rates Decision, dated April 12, 2012, pages 83-84:

> The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.
>
> While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.

(b) Please refer to YEC-YECL-12(b) Attachment 1. The charges to the reserve are related to capital projects for replacement of assets.

(c) Please refer to YEC-YECL-12(c) Attachment 1 for an illustrative example of how the proposed deferral would operate.

(d) Yukon Electrical is not aware of any other similar deferral accounts currently approved / used by other regulated utilities in Canada.

The Yukon Electrical Company Limited
Continuity Schedule of Reserve for Site Restoration

	YEAR					
	2008	2009	2010	2011	2012	
Beginning Balance	(4,688)	(5,379)	(4,677)	(4,559)	(4,497)	
Total Depreciation Expense	(535)	(103)	-	-	-	
Amortization of Differences	(131)	769	-	-	-	
Costs of Removal	49	50	185	100	64	Note 1
Gross Salvage	(74)	(14)	(68)	(38)	(10)	
Ending Balance	(5,379)	(4,677)	(4,559)	(4,497)	(4,443)	

Note 1 - Cost of Removal Detail

		YEAR				
		2008	2009	2010	2011	2012
Group Account	Group Account Description					
44200	Int Combust Structures	-	-	5	-	-
	Int Combust Generators	-	-	-	2	-
47300	Poles and Fixtures	12	22	110	57	35
47400	Overhead Conductor	19	8	8	11	1
47500	Underground Conduit	5	6	8	1	3
47610	Meters	-	-	5	2	7
47710	Distribution Substation	10	9	4	-	-
47810	Street Lights	-	2	13	17	0
47910	Transformers	3	4	32	9	18
	Total	49	50	185	100	64

The Yukon Electrical Company Limited
Illustrative Example of Proposed Depreciation Deferral

For account 47300, the Average Service Life determined by the depreciation study is 45 years. New information becomes available to Yukon Electrical that causes the company to believe that this assumption may no longer be accurate, and that the actual Average Service Life is now only 39 years. As a result, the change in life depreciation expense is as follows:

Based on depreciation parameters determined by the current depreciation study:

Account	Description	Life Parameter	Forecast Cost	Life Expense	Life Rate
47300	Poles & Fixtures	R3-45	36,821,587	883,748	2.40%

Based on updated parameters:

Account	Description	Life Parameter	Forecast Cost	Life Expense	Life Rate
47300	Poles & Fixtures	R3-40	36,821,587	1,006,220	2.73%

As a result, Yukon Electrical would have to record an additional $122,472 of depreciation expense in its financial statements for 2014.

Pre-Tax Impact of Change in Depreciation Expense	174,960
Pre-Tax Impact of Change in Rate Base	(5,505)
Additional Amount to Be Collected From (Refunded to) Customers	169,454

YEC-YECL-13

Reference: Section 8 – Return on Rate Base – Cost of Capital

Request:

(a) Please provide a copy of BCUC Order G-75-13.

(b) Please provide details and discuss YECL's proposal of using Automatic Adjustment Mechanism (AAM) and ROE Deferral Account, including:

(i) if YECL proposing that the AAM method for YECL will be the same as for the utilities in British Columbia affected by British Columbia Utilities Commission (BCUC) Order G-75-13 and any future changes to BCUC Order G-75-13 will affect YECL ROE;

(ii) how and when (beginning of the year, when Canada Bond yield changes or other) YECL is proposing to calculate AAM;

(iii) what would be basis for calculating of difference in ROE, including Rate Base (timing and amount, i.e. YUB approved Rate Base for test year or actual Rate Base at the time of adjustment), common equity ratio (timing and ratio);

(iv) by providing examples and impacts to the test years by assuming 10% higher and 10% lower long-term Canada Bond yield compared to the yield rate used for calculation of 9.21% ROE.

(c) Please confirm that per paragraph 3 of British Columbia Utilities Commission Order G-75-13 "[t]he implementation of the model [AAM] will be subject to conditions outlined in the Decision."

(d) Please provide details of the conditions outlined in the BCUC Order G-75-13 as per c) above.

(e) Please confirm that the proposed AAM and ROE deferral account does not go beyond 2013-2015 test years. If not confirmed please explain why?

(f) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(g) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) Please refer to YEC-YECL-13(a) Attachment 1.

(b) (i) Yukon Electrical is proposing to adjust its 2014 and 2015 ROE in accordance with any adjustments that may be made to the ROE of the benchmark utility in British Columbia as a result of the application of the AAM formula, as calculated and determined by the BCUC.

(ii) It will be the BCUC that calculates the quantum of the AAM. The precise timing and mechanics of the AAM formula and its application are currently being determined by the BCUC, but Yukon Electrical understands the intent is for the AAM formula to be applied annually in advance of any given test year.

(iii) Should there be a change in the 2014 or 2015 BCUC GCOC ROE benchmark as a result of the AAM, Yukon Electrical proposes to base the adjustment on the YUB approved rate base and common equity ratio for each of those years.

(iv) Please refer to WL-YECL-16(b) for an illustration of the impact to ROE and Yukon Electrical's revenue requirement as a result of potential changes in the Long Canada Bond Forecast.

(c) Confirmed.

(d) As per pages 91 and 92 of the May 10, 2013 BCUC GCOC Decision:

> "To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded.

> Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent."
>
> "FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015."

(e) Confirmed.

(f) Not confirmed. The BCUC is re-instituting an AAM as it has the potential to contribute to regulatory efficiency by avoiding frequent costly and time consuming ROE proceedings, and did not note in its decision any impact the AAM formula has on the risk profile of the benchmark utility.

(g) Yukon Electrical has not conducted an exhaustive search of similar mechanisms used in other regulatory jurisdictions. In British Columbia, the AAM will be used by: FortisBC Inc., FortisBC Energy (Vancouver Island), FortisBC Energy (Whistler), Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.

In accordance with prior Yukon Board direction, Yukon Electrical is proposing to link its ROE to the recently approved BCUC GCOC benchmark rate plus a risk premium, and, consistent with the BCUC Decision, to include a mechanism for adjusting its ROE in step with any changes to the ROE of the BCUC benchmark utility resulting from the application of the AAM formula.

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING
(STAGE 1)

DECISION

May 10, 2013

Before:

D.A. Cote, Commissioner/Panel Chair
R. Giammarino, Commissioner
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner

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EXECUTIVE SUMMARY

By Order G-20-12 on February 28, 2012, the British Columbia Utilities Commission (Commission) initiated the Generic Cost of Capital (GCOC) proceeding pursuant to section 82 of the *Utilities Commission Act* to review and determine among other things, the following:

- The setting of the appropriate cost of capital for a benchmark low-risk utility;
- The possible return to an automatic adjustment mechanism (AAM) for setting the return on equity (ROE) for the benchmark utility each year; and
- The establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt.

By Order G-48-12 on October 11, 2012, the Commission established the following:

- The proceeding will have two stages; Stage 1 will determine the cost of capital for the benchmark utility and Stage 2 will establish the cost of capital for other utilities as compared to the benchmark.
- Fortis Energy Inc. (FEI) in its pre-amalgamation state will serve as the benchmark utility for the GCOC proceeding; and
- An oral public hearing commencing on December 12, 2012, will be held to determine the cost of capital for the benchmark utility.

Fair Return Standard

The Fair Return Standard is foundational for cost of capital proceedings and has three requirements for a fair and reasonable return on capital: the comparable investment requirement, the financial integrity requirement, and the capital attraction requirement. The Commission Panel, consistent with previous decisions and the regulatory compact, confirms that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. In the current proceeding, the Commission Panel has not considered the rate impacts of the revenue required to yield the fair return but has noted that by seeking an optimal capital structure and the opportunity cost of capital, the needs of customers are being served.

Contextual Issues

Three important issues were raised that were contextual in nature; the significance of past cost of capital decisions, the significance of decisions from other jurisdictions and the relevance of the disparity between "allowed" and "actual" ROE.

With respect to past cost of capital decisions and appropriate points of reference, the Commission Panel accepts that the 2009 Decision is a reasonable point of reference with respect to long-term risk as this is the most recent proceeding and has been used extensively by the parties. The Panel also remains open to looking back to the 2006 ROE Decision where appropriate.

With respect to reliance upon data from US jurisdictions, the Commission Panel has determined that it is appropriate to continue to accept the use of historical and forecast data but do not accept that US data should be considered to be the same or be given equal weight as data for Canadian utilities. Concerning Canadian jurisdictional decisions, the Panel acknowledges the importance of considering methodologies, approaches, and regulatory principles related to other jurisdictions' decisions but does not accept the use of results and values for the purpose of calibration.

Concerning the relevance of disparity between FEI's "allowed" and "actual" ROE, the Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from FEI's positive track record. However, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach. Additionally, the Panel is of the view that these differences are assessed in revenue requirement proceedings.

Capital Structure

In determining an appropriate capital structure for the benchmark utility, the Commission Panel considered FEI's long and short-term risk, development of an optimal capital structure, credit ratings and metrics and experiences of other jurisdictions.

The Commission Panel is supportive of maintaining an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.

Return on Equity

The Commission Panel considered expert evidence on various model approaches to determine ROE. The Panel finds that the discounted cash flow model and the capital asset pricing model should be given equal weight in determining the ROE of the benchmark utility. No weight was given to the equity risk premium and comparative earnings models. The Commission has determined that an ROE of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the benchmark utility. The benchmark utility ROE will be effective January 1, 2013 and will be effective until December 31, 2015, subject to updating as a result applying the AAM formula.

Automatic Adjustment Formula

Consideration was given to re-instituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings, which had been eliminated in the 2009 Decision. In addition, consideration was given to the status of AAMs in other jurisdictions and what optional AAMs might be considered. The Commission Panel has determined that it is appropriate to re-establish an AAM formula noting that it better meets the FRS than giving no consideration to the market changes over the period between ROE proceedings. The Panel has directed that a two variable model considering changes to utility bond spreads and the long-term Canada bond yield be

established to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

Cost of Capital – Small Utilities

Stage 1 of the GCOC proceeding considered the cost of capital for the benchmark utility, FEI. Stage 2 will assess the differences in short and long-term risk faced by regulated utilities in British Columbia other than FEI and their impact on the capital structure and ROE for these utilities. The Commission Panel has recommended that the utilities be separated into three groups, each of which will be handled separately. The Commission Panel has also made a number of determinations and findings with respect to the handling of the size factor as a business risk and deemed short and long-term debt interest rates.

1.0 INTRODUCTION

1.1 Background

The 2009 ROE Decision[1] (2009 Decision) was issued concurrently with Order G-158-09 on December 16, 2009. The Order set the return on equity for FEI, the benchmark utility in British Columbia, at 9.5 percent effective July 1, 2009, and the equity ratio at 40 percent effective January 1, 2010. Order G-158-09 also eliminated the AAM, which had been utilized to set the ROE for the benchmark utility annually. Since that Order, there have been no further adjustments to the ROE or capital structure of the benchmark utility.

This Decision for Stage 1 of the Generic Cost of Capital (GCOC) proceeding sets out:

- the new approved ROE and capital structure for FEI;
- the new automatic adjustment formula and the conditions under which it will be in effect; and
- the framework to review the cost of capital for small utilities.

Stating that changes have occurred in the financial markets since the 2009 Decision, the Commission, by Order G-20-12 dated February 28, 2012, initiated the GCOC proceeding pursuant to section 82 of the *Utilities Commission Act* (*UCA*) to review and determine, among other things, the following:

- the ROE and capital structure for a benchmark low-risk utility;
- the possible return to an AAM to set the ROE for the benchmark utility each year; and
- a deemed capital structure and deemed ROE for small utilities, particularly those utilities without short-term debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. The Order further divided the list of utilities regulated by the BCUC into Affected Utilities and Other Utilities. The Affected Utilities have been so designated given their active participation in previous ROE proceedings or their anticipated interest

[1] In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and capital Structure Decision, December 16, 2009.

in the GCOC proceeding as investor-owned utilities. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. The Other Utilities are so designated as they have not actively participated in previous ROE proceedings and they were not expected to file evidence in the GCOC proceeding.

On April 18, 2012, the Commission, by Order G-47-12, issued a final scoping document, which set out the purpose and scope of the proceeding. On April 19, 2012, the Commission issued a preliminary draft of the minimum filing requirements. Following submissions by Registered Interveners, the Commission issued Order G-72-12 on June 1, 2012, which set out the minimum filing requirements for those utilities expected to participate and a preliminary regulatory timetable. In an attachment to Appendix A to the Order, the Commission also placed on the record the terms of reference for a Survey of Cost of Capital Practices in Canada prepared by the Commission consultant, the Brattle Group (Brattle Report).

On October 11, 2012, following a procedural conference held on October 4, 2012, the Commission by Order G-148-12 established that in 2012, FEI in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding. The Order also established an oral public hearing to commence on December 12, 2012, to hear the cost of capital for the benchmark utility. In addition, it was determined that the proceeding will have two stages: Stage 1 establishing the ROE and capital structure for FEI the benchmark utility, and Stage 2, establishing a cost of capital for other utilities as compared to the benchmark utility.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

The Commission determined the purpose and scope of the GCOC proceeding in Order G-47-12, with certain outstanding matters such as the appropriate utility, which would serve as the benchmark utility, determined by Order G-148-12 dated October 11, 2012. The purpose and scope of this proceeding are as follows:

PURPOSE OF THE PROCEEDING

The main purposes of the GCOC Proceeding are:

I. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;

II. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and

III. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

SCOPE OF THE PROCEEDING

I. The appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity, and interest on debt.

II. Establishment of a Benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year.

III. Whether re-establishment of an ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is accepted as a result of the GCOC Proceeding, it would be implemented January 1, 2014. If not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013 on a regular basis.

IV. A generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility.

V. In certain circumstances, a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate.

VI. In certain circumstances for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM). If warranted, the Interest AAM would be implemented for January 1, 2014. If not warranted, setting a future regulatory process on how the deemed interest for a benchmark low-risk utility would be adjusted in future years beyond December 31, 2013.

1.3 Regulatory Process

As noted previously, the Commission retained The Brattle Group to prepare a survey report on the Cost of Capital Practices in Canada. The Brattle Report, filed as Exhibit A2-3 on June 8, 2012, provides a description of the cost of capital estimation methods and the common approaches in implementing the results in Canadian jurisdictions. The Brattle Report was intended to provide context and background for the establishment of the cost of capital of a low-risk benchmark utility

in B.C. All parties were provided with the opportunity to file Information Requests (IRs) on the Report.

In accordance with Order G-72-12, the following utilities filed minimum filing requirements:

- FEI, FortisBC Inc. , FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC (Whistler) Inc. (FEW),[collectively (FBCU)];
- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. [collectively (PNG)]; and
- Corix Utilities (Corix).

The Industrial Customers Group of FortisBC Inc. (ICG) and the BC Utility Customers comprising the Association of Major Power Customers of BC (AMPC), the British Columbia Pensioners' and Seniors' Organization (BCPSO), and the Commercial Energy Consumers of BC (CEC) were active in the proceeding. Two rounds of IRs with respect to evidence filed by Affected Utilities and one round of IRs on evidence filed by Interveners took place.

The oral public hearing, including an *in camera* session on FBCU's confidential reports, took place over a period of seven days between December 12, 2012 and December 21, 2012. FBCU tendered five witness panels for cross-examination and Corix, BC Utility Customers, and the ICG each had one witness panel for cross-examination.

A list of procedural orders in the GCOC proceeding is included in Appendix A. A list of Appearances is included in Appendix B and Appendix C contains a list of witness panels that gave evidence. Appendix D contains the List of Exhibits. Appendix E contains a risk matrix used in a recent Commission decision with respect to a small utility that is Appendix B to Order C-1-13, Appendix F contains summary tables of ROE estimates by expert witnesses retained by the utilities and ratepayer groups, and. Appendix G is a list of acronyms.

1.4 Approach to Decision

The legal framework for determining a fair return for a regulated utility is called the "Fair Return Standard" and is discussed in Section 2.

There are a number of broader issues of importance, which were raised by this proceeding. These are contextual in nature and include the following:

- importance of past cost of capital decisions;
- consideration of decisions from other jurisdictions; and
- the relevance of the disparity between "allowed" and "actual" ROE.

These issues are discussed in Section 3 and provide the Commission Panel with a context to assist in reviewing and assessing the evidence.

Section 4 deals with an appropriate capital structure given FEI's level of risk with consideration of credit ratings and metrics and decisions in other jurisdictions. Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses. Section 6 examines potential AAM models and whether there is justification to return to a reliance on such a mechanism. Section 7 considers issues related to cost of capital for small utilities, and Section 8 examines the need for financial models presented in proceedings such as this to have a sound theoretical basis.

2.0 LEGISLATIVE FRAMEWORK – THE FAIR RETURN STANDARD

2.1 Legislative Requirement

The enabling legislation for the BCUC, the *UCA*, provides that a public utility must not make, demand or receive:

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia;

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

A rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or

(c) unjust and unreasonable for any other reason.[2]

The *UCA*, and other Canadian legislation delegating power to regulatory tribunals, follow what is known as the "Regulatory Compact." In general terms, the Regulatory Compact states that in exchange for an exclusive franchise to serve a defined area:

- a regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at cost-based rates as prescribed by the regulatory tribunal, and
- the regulatory tribunal must allow the regulated utility an opportunity to earn a fair return on its invested capital.

(Exhibit C4-9, p. 7; BCPSO Final Submission, p. 3)

The approach to determining a fair return on the cost of invested capital in a regulated utility has normally been referred to as the Fair Return Standard (FRS).

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[2] *UCA* sections 59 (1) (a) (b), 59(5), 60 (1) (a) (b) (i)

2.2 Elements of a Fair Return Standard

The Supreme Court of Canada decision in *Northwestern Utilities Ltd*. v. *Edmonton (City),* [1929] S.C.R. 186, (*Northwestern Utilities*) at pages 192-193 describes the FRS as follows:

> "The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (per Lamont J.)

The Brattle Report notes that the legal decisions, which provide the overarching principles of the FRS, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. In other words, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (Exhibit A2-3, pp. 2-3)

On page 8 in the 2009 Decision, the Commission endorsed the National Energy Board's (NEB) articulation of the Fair Return Standard in NEB Decision RH-1-2008 where NEB stated:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - Be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - Enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

Ms. McShane, the expert witness for FBCU, submitted that the standards for a fair return arise from legal precedents and there are three requirements the utility must:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and
3. Attract capital on reasonable terms.

According to Ms. McShane, the legal precedents make it clear that the three requirements are separate and distinct. The FRS is met only if all three requirements are satisfied. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8)

Dr. Laurence Booth, the expert witness for the BC Utility Customers, submitted that the definition of a fair rate of return was confirmed in *BC Electric* [*Railway Co. Ltd. v. Public Utilities Commission of B.C. et al ([1960] S.C.R. 837)*] when Mr. Justice Lamont adopted the definition of a fair rate of return, put forward in *Northwestern Utilities*.

Dr. Booth submitted that the definition in the *Northwestern Utilities* is referred to as an opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. Dr. Booth further submitted that to any modern financial economist, Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a risk adjusted discount rate or expected rate of return. (Exhibit C6-12, pp. 7, 8)

2.3 Application of the Fair Return Standard

The Commission Panel observes that the application of the FRS leaves room for disagreement, judgment and discretion. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure. (Exhibit A2-3, p. 2)

The Panel also notes the words of the Alberta Utilities Commission (AUC) on this subject related to conflicting evidence and applying judgment:

> "....the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the TransCanada Pipelines decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors."[3]

The Commission Panel further notes the words of the Federal Court of Appeal's ruling in *TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149* on just and reasonable tolls. It quotes the *Northwestern Utilities* and states:

> "Tolls which reflect a fair return on capital will be just and reasonable to both the Mainline and its users.

It further states:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the point of view of the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring Mainline's costs are not overstated .... And, specific to this appeal, customers and consumers have an interest in ensuring that the Mainline's cost of equity is not overstated."
>
> (TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149, para. 33, 34)

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[3] AUC 2009 Generic Cost of Capital Decision, November 12, 2009, p. 28

Submissions by Parties

None of the parties disagree with the Fair Return Standard as the applicable test. The Utilities and Interveners, however, disagree on how this test should be applied.

FBCU take the position that the overall rate of return allowed for FEI must be based on the utility's true cost of capital without compromising the legitimate cost of service to achieve lower rates in the short-run. FBCU submit that the combination of allowed ROE and capital structure should permit FEI to maintain credit ratings that are at a minimum in the "A" credit category in varying market conditions. This matter is further addressed in Section 4.5.

FBCU argue that a fair return is not synonymous with the lowest possible return. It pointed out that in the 2006 ROE Decision (2006 Decision),[4] the Commission had articulated that the "lowest possible" was not the appropriate test. Therefore, FBCU submit that the Commission should not rely on evidence on rate impacts and that the view of Dr. Safir, ICG's expert witness, that the outcome of a "fair return" should always favour the lower range is fundamentally inconsistent with the authorities on the FRS. (FBCU Final Submission, pp. 1, 7, 11-12)

The AMPC/CEC do not dispute the definition of the FRS based on the NEB Decision RH-1-2008 and endorsed by the Commission in the 2009 Decision. However, the AMPC/CEC disagree with FBCU's submission that the three requirements listed are the only factors to be considered when deciding what constitutes a fair return, with no consideration of the Commission's broader mandate to balance the interest of customers and regulated utilities. AMPC/CEC submit that when acting as the surrogate for competition, the Commission cannot and must not protect FEI from all business and financial risk by unnecessarily raising the ROE and common equity at the expense of customers; and the Commission must scrutinize whether the cushion FEI asks for is truly necessary to meet the FRS in light of its broader mandate to protect consumers. In Section 4.5 of this Decision, the Commission Panel discusses the application of the FRS and the role of credit metrics in the implementation of the FRS requirements.

[4] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision and Order G-14-06, March 2, 2006.

According to AMPC/CEC, Dr. Booth's evidence shows that he recommended a fair return by applying the principle in the FRS that "only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair." In addition, AMPC/CEC state that among other things, Dr. Booth checked his findings against numerous independent, reputable sources which confirmed that his estimates were reasonable. (AMPC/CEC Final Submission, pp. 5-7)

The BCPSO agrees with FBCU's characterization of the FRS and agrees that utilities are entitled to a competitive return as defined in the FRS' three tests regardless of the rate impact. However, BCPSO submits that it is not the same as to say that customer interests carry no weight in setting an appropriate deemed cost of capital as utility customers have an interest in ensuring that the utility's cost of capital is not overstated. BCPSO submit that a fair return is one that takes into account the right of utility customers to pay no more than a fair and reasonable charge for the service provided. Based on its logic, BCPSO submits that the evidence from Exhibit B1-42 which compares the rate impact of a 5 percent change in the equity ratio to a 50 and 100 basis point change in ROE is admissible; and furthermore, if the utility can be provided a competitive return with less rate impact, that option should be chosen. (BCPSO Final Submission, pp. 3-5)

ICG submits that the interests of customers should be paramount to those of the shareholders and reiterates Dr. Safir's testimony that where a range of competitive returns is available for evaluation, the outcome of a "fair return" should always favour the lower range presented. (ICG Final Submission, p. 3)

In Reply, FBCU submit that the Commission would err in accepting ICG's argument that regulation is simply to benefit customers. FBCU submitted that the Commission, in the 2009 Decision, had been explicit that it was not accounting for rate impacts in reaching its decision. (FBCU Reply, pp. 2-3)

Commission Determination

In previous decisions, the Commission concluded that the opportunity to earn a fair return must be provided to each regulated utility as a separate obligation from those service and financing requirements detailed in other sections of the *UCA*. For instance, on page 8 of its 2006 ROE Decision, the Commission said:

> "In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."

The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility. This Decision reiterates the principle articulated in the 2006 ROE Decision and the 2009 Decision, and argued by FBCU on pages 7 to 9 in its Final Submission, that the Commission does not consider the rate impacts of the revenue required to yield the fair return. However, by seeking an optimal capital structure and the opportunity cost of capital we are serving the needs of the customer.

While this Commission Panel has not considered the rate impacts of the revenue required to yield the fair return *per se*, we are of the view that the capital structure of the utility should be set efficiently and, therefore, there is value in finding an optimal capital structure. Exhibit B1-42 provides comparative information on revenue requirements for FEI based on either a change in equity thickness or a change in ROE. The ICG submits that the Commission should reduce the ROE before reducing the capital structure of FEI. (ICG Final Submission, p. 4) In this regard, the Commission Panel finds the information on rate impacts as presented in Exhibit B1-42 useful. An optimal capital structure is discussed further in Section 4.4.

3.0 CONTEXTUAL ISSUES

This section considers important issues raised by this proceeding that are contextual in nature; they include:

- The significance of past cost of capital decisions;
- The relevance of US data and the significance of decisions from other jurisdictions; and
- The relevance of the disparity between "allowed" and "actual" ROE.

3.1 Past Cost of Capital Decisions

An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel's decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time. Each of these referenced areas will be discussed in turn.

Submissions by Parties

3.1.1 Changes in Capital Markets

Throughout this proceeding, the FBCU have relied upon and underlined the Commission's statement that changes have occurred in capital markets since the 2009 Decision was issued. They have taken the position that capital markets are similar (albeit for different reasons) to what they were in the fall of 2009 when the previous cost of capital proceeding took place. The FBCU have relied very heavily on the 2009 Decision as a reference point for the current proceeding and have provided comparisons between what they believe exists today as opposed to conditions which existed at the time of the 2009 Decision. FBCU have relied upon the opinion evidence prepared by two of their expert witnesses, Ms. McShane and Mr. Engen, which showed that many of the key indicators of conditions within capital markets are similar and in some cases worse than the same indicators reflecting capital markets late in 2009. FBCU maintain that the experts along with market indicators

and Bank of Canada published information all suggest that equity capital markets in Canada are challenging and volatile and the market cost of equity has risen since 2009. In summary, FBCU maintain that current market conditions provide no basis for reducing FEI's overall return as argued by interveners. (FBCU Final Submission, pp. 1-2, 16-30)

ICG takes issue with FBCU on their choice of 2009 as an appropriate reference point and argue that a more appropriate reference point was the 2006 Decision. ICG submits that the 2009 Decision did not appropriately balance the interests of customers and shareholders and gave inappropriate weight to the interests of shareholders. Moreover, ICG submits that the 2009 Decision represented a significant departure from previous Commission cost of capital decisions. With respect to its Canadian peers, ICG points out that the weighted equity return component was materially lower (by 0.47) in 2005 through 2009 and materially higher (by 0.57) in the 2010 to 2012 period. ICG argues that the 2009 Decision should not be a point of reference for this decision given a steady decline in FEI's business risks since 2005. (ICG Final Submission, pp. 11-12)

BCPSO also takes issue with the use of the 2009 Decision as a reference point for this decision, expressing concern as to whether the capital market conditions comparator dates are consistent across the two proceedings. BCPSO submits that the current proceeding is forward looking with respect to capital conditions and snapshot-style evidence of past capital conditions is of limited value. In its view, the economic tests such as equity risk premium (ERP), comparable earnings (CE) and discounted cash flow (DCF) provide a better basis in assessing cost of capital stating that they "are more precise, forward looking, and can be made industry or company specific." The primary value of evidence relating to general market conditions lies in the trends it demonstrates. (BCPSO Final Submission, p. 6)

AMPC/CEC submit that regulators do not base a cost of capital decision on immediate circumstances only. They assert that the Commission will consider economic and financial conditions occurring since the last hearing and will also consider the outlook on a going forward basis. Referring to Mr. Engen's S&P/TSX Composite Index 10 Year Performance data, AMPC/CEC state that the difference now "is that the last few years have witnessed the market hold or increase ground it recovered, whereas in the lead up to the 2009 hearing, it had just suffered a dramatic crash." They further point out the FBCU argument that capital markets are similar to what they were in 2009 is in conflict

with their own witnesses' (Ms. McShane and Dr. Vander Weide) DCF calculations, which have declined considerably since the close of evidence in the last hearing. (AMPC/CEC Final Submission, pp. 28-29; Exhibit B-1-9-6, FBCU Evidence, p. 14, updated in Exhibit B-1-49)

In Reply to ICG, the FBCU state that the choice of 2009 as a point of comparison is because that proceeding is where the Commission most recently assessed FEI's business risk. To disregard this in favour of the 2006 Decision because ICG preferred the outcome in FBCU's view is indefensible. (FBCU Reply, p. 21)

Concerning the AMPC/CEC's submissions regarding the inconsistency in capital markets being similar to 2009 and FBCU's witnesses' DCF calculations, the FBCU state the following:

- Mr. Engen's evidence relates to the overall capital market and trends in the market cost of equity which indicate the market cost of equity is higher today.
- Ms. McShane's and Dr. Vander Weide's DCF calculations relate to a narrow segment of the overall market and deal specifically with FEI's cost of equity. (FBCU Reply, p. 5)

3.1.2 Changes in Long-Term Risk

While there has been considerable disagreement with respect to relying upon 2009 capital markets as a reference point for comparison, there has been little concern raised by the parties with respect to using the 2009 Decision as a reference for changes in long-term risk. Both the FBCU and interveners have relied heavily on what has changed since 2009 and in some cases referred back to the period prior to the 2006 Decision as a source of comparison.

Commission Discussion

The Commission Panel accepts that many of the indicators reflecting the current state of the capital markets are similar to what they were in 2009. This, however, does not mean that the conditions under which the 2009 Decision was made are the same as they are today. As noted in Mr. Engen's evidence, the current period is characterized by concerns for a sustained US economic recovery, fears of an economic slowdown related to weak economic data from the US and the European Union and the European sovereign debt crisis, among other things. These are not at all descriptive

of the period in latter 2009. (Exhibit B1-9-6, Appendix E, Engen Evidence, pp. 7-8) Moreover, as pointed out by AMPC/CEC, since that time markets have demonstrated a degree of stabilization in sharp contrast to the situation preceding the 2009 Decision which followed a dramatic crash. Therefore, while there are some similarities between the current period and late 2009, the Panel is of the view there are significant differences. By contrast, the markets, while maintaining volatility, have experienced a few years of comparative stability and the investor has been distanced from the financial conditions characterizing the period leading to the 2009 proceeding.

The Commission Panel is mindful that many of the key indicators of capital market conditions are similar to those of 2009 but does not consider them alone to be determinative in reaching a decision on the cost of equity. While considering changes in capital markets, pricing models some of which reflect the market outlook, are very important in reaching a determination on the appropriate rate of return in this proceeding.

The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

The Commission Panel does not accept ICG's argument that the 2009 Decision fails to appropriately balance the interests of customers and shareholders. In the view of the Panel, there is no value in re-examining the 2009 Decision nor is there evidence to support the need for doing so.

3.2 Consideration of Other Jurisdictions

Throughout the evidentiary portion of this proceeding there has been considerable reliance among the parties upon data and cost of capital decisions from both US and Canadian jurisdictions. The Commission Panel considers these separately as the issues related to each differ.

3.2.1 Relevance of US Data and Decisions

In the 2006 Decision, two issues related to reliance upon US data in cost of capital proceedings were dealt with by the Commission:

1) Opportunities exist for investors to commit capital on a global basis. The Commission Panel noted that there was considerable foreign exchange risk and was not convinced that the Federal Government's easing of foreign content in retirement portfolios was sufficient reason to raise the equity return of a utility.
2) The necessity of looking beyond Canadian data in measuring the risk premium. The Commission accepted the use of historical and forecast data for US utilities "when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results." (2006 Decision, p. 50)

In the 2009 Decision, the Commission accepted the use of historical and forecast data of US utilities as outlined in the 2006 Decision. In addition, the Commission supported the need for utilities to compete in a global marketplace and reiterated its acceptance of the use of historical and forecasting data. In the 2009 Decision, the Commission also noted the lack of relevant Canadian data and considered the potential for US gas utilities to act as a proxy in the determination of cost of capital and credit metrics. (2009 ROE Decision, pp. 15-16)

Submissions by Parties

In the current proceeding, the FBCU take the position that the Commission should find that US data remains useful and that US utilities can be appropriate comparators based on total investment risk. In support of this, they rely on the evidence of Ms. McShane and Dr. Vander Weide who make the following assertions:

- The operating, regulatory and business environments for US and Canadian regulated companies are generally similar.
- Capital markets in Canada and the US are significantly integrated and the cost of capital environment is similar.

In further support of their argument, the FBCU note that Dr. Safir acknowledged the integration of capital markets in his evidence and utilized US companies in his Capital Asset Pricing Model (CAPM) and DCF analysis. Further, the FBCU argue that Dr. Booth, in spite of his concern with the use of US data, conceded there was a high degree of integration between US and Canadian markets. (FBCU Final Submission, pp. 96-97)

AMPC/CEC's witness Dr. Booth raised two concerns with the use of US data:

- US financial markets exhibit greater risk than Canadian markets and have generated higher premia in the past.
- Regulatory implementation differs even though US and Canadian principles of regulation are the same.

  (Exhibit C6-12, Dr. Booth Evidence, Appendix B, p. 106)

AMPC/CEC submit that there is ample support for Dr. Booth's assertion that US markets are riskier than those in Canada. They point out his evidence demonstrates that over the period 1926-2011, US returns showed greater volatility than Canadian returns and the risk premium was higher in the US than the equivalent in Canada. They further submit that during Ms. McShane's cross-examination, she agreed that a typical US utility could be viewed as higher risk than a Canadian one and point out that her report aligns with Dr. Booth's as it presents a historical risk premium of 4.7-4.8 percent for Canada compared to 5.5-5.7 percent for the US. (AMPC Final Submission, p. 46) Concerning the difference between Canada and the US with respect to the implementation of regulatory principles, AMPC/CEC state that the Commission in the 2009 Decision was cognizant of the danger of relying on US comparables and cites the following statement of the Commission Panel in that decision:

> "The Commission Panel agrees with Dr. Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short term, earn its allowed return than the Value Line US natural gas LDC enjoy." [emphasis added by AMPC/CEC]

Additionally, AMPC/CEC point to Dr. Booth's finding that Canadian utilities have higher bond ratings in spite of poorer financial ratios, which in his view reflects the importance bond rating agencies place on the differing regulatory approaches in Canada and the US. In summary, AMPC/CEC submit that the Commission should continue to approach US data based results with caution, adjusting them downward to reflect differences in financial and regulatory contexts between the two countries. (AMPC/CEC Final Submission, pp. 46-47)

FBCU argue that the evidence does not support a downward adjustment to US results and state the following:

> "Since the financial crisis, long term interest rates have been similar in Canada and the US across a broad range of bond types, equity market volatility has been virtually identical, and market risk premium surveys show virtual identical values." (FBCU Reply, p. 28)

None of the parties have suggested that the Commission should put no weight on US data and decisions.

Commission Determination

The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. **Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.**

In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. Canadian investors considering US utility investments are subject to currency exchange risk that would not be the case with Canadian utility investments. Additionally, the US regulatory

environment while similar is not identical to that of Canada. The 2009 Decision's reference to the array of deferral mechanisms resulting in greater certainty for the Canadian utility is just one example of potential differences between the jurisdictions. Moreover, Ms. McShane has acknowledged under cross-examination that the universe of US utilities is focused on vertically integrated utilities and, to the extent that there is a smaller number of Canadian investor-owned, vertically integrated utilities, the typical US utility could be viewed as higher risk than the typical Canadian utility. (T3:466-467) Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

3.2.2 Consideration from other Canadian Jurisdictions

Throughout this proceeding the parties have chosen to utilize information and related decisions from other Canadian jurisdictions as support for the position they have taken on an issue. The Commission Panel notes that decisions in all jurisdictions result from the judgment of evidence specific to a region or a particular utility that in each case is unique. To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C.

3.3 Relevance of Disparity between "Allowed" and "Actual ROE"

3.3.1 Outline of the Issue

As described in Section 2.1, when setting a rate under the subsection 60 of *UCA,* the Commission must have due regard for, among other things, whether the rate is insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. This standard does not mean, however, that a utility must be guaranteed its allowed return on equity. It simply means that a utility must be given an opportunity to earn this return. In any particular year, the actual ROE earned may be below or above the

allowed ROE. The rates are set based on a forecast revenue requirement for the year, which includes a provision for the allowed ROE, grossed up for income taxes. The utility's actual performance during the fiscal year will determine how close the actual ROE will be to the allowed ROE.

Short-run risks in general relate to a utility's ability to annually earn its allowed return on equity. The issue for the Panel, therefore, is to determine the relevance of the difference of realized and allowed ROE. From the investors' perspective, this risk relates to the relative stability of year-to-year variations in earnings or cash flows and the value of those cash flows. Therefore, the Panel first has to assess the relevance of the disparity between "allowed" and "actual" ROE in relation to the question of whether FEI faces any short-run risks. FEI has a track record of generally achieving, and often exceeding, the allowed ROE in any particular year. Does this strong track record imply FEI having "no material short-run risk, or the risk of return on capital" as claimed by Dr. Booth? (T8:1464)

FEI's track record was explored extensively in the proceeding as shown below:

- From 2002 to 2011, there was only one year when the actual ROE was below the allowed ROE, whether assessed on a pre or post earnings sharing mechanism basis. This year was 2010, when 9.42 percent was achieved as compared to the 9.50 percent allowed, resulting in a net income variance of $1.2 million. (Exhibit B1-20, BCUC 1.95.1)
- A similar trend is also apparent from 1994 to 2001. (Exhibit B1-10, BC Utility Customers 1.2.1; Exhibit C6-12, pp. 27-29)
- FBCU stated that the data set used by Dr. Booth is largely from years in which a Performance Based Rate (PBR) mechanism was in place for FEI. During the PBR period, O&M and capital were set through a formula, not based on forecast spending. The PBR formula approach was designed to result in savings to be shared with customers, primarily from the operational consolidation of three separate utilities. The Commission–approved framework expressly anticipated earnings that were above the allowed ROE. FBCU argue that when the periods under PBR are excluded, the variances between FEI's achieved return and allowed ROE from 1994 to 2011 were not that significant. (FBCU Final Submission, p. 40; Exhibit B1-20, BCUC 1.96.1.1)
- For the PBR period 2004 to 2009, after sharing, the average ROE over the period is .67 percent over the allowed ROE. (Exhibit B1-32, Rebuttal Evidence, p. 3)

Submissions by Parties

FBCU submit that the relative consistency of utility sector earnings in Canada tends to suggest lower short-term risk than for non-regulated companies, but "is not synonymous with an absence of short-term risk." (FBCU Final Submission, p. 39)

ICG submits that the Commission Panel should not accept that consistent over-earnings can be explained by PBR, and that consistent over-earning is attributable to how effectively FEI manages the regulatory risk, which it claims is its largest risk, not how effectively FEI operates the utility. ICG further argues that one should think of over-earnings during the PBR period as a regulatory benefit that can be enhanced to provide increased earnings that exceed the Fair Return Standard, and that "…the historic returns suggest that FBCU have come to expect returns that exceed a fair return." (ICG Final Submission, p. 16)

AMPC/CEC first observe that FEI has not experienced any significant risk as "the shareholder has not cumulatively lost any money whatsoever since 1994." AMPC/CEC submit that "year after year, FEI continues to face very little short-run risk, such that this pattern of consistent overearnings is clearly a long-term phenomenon." (AMPC/CEC Final Submission, p. 9)

In Reply, FBCU submit "the similarly long track record among Canadian utilities of achieving or exceeding their allowed ROE suggests that Canadian regulators have long recognized that it is reasonable for a well-managed utility to be able to achieve its allowed ROE on a consistent basis." (FBCU Reply, p. 10)

Commission Determination

The Panel notes that FBCU did not explain why, even after allowance for the sharing mechanism, the over earnings have continued. For instance, in 2011 the actual ROE was 10.15 percent as compared to the 9.50 percent allowed. Consequently, the Panel observes a noteworthy asymmetry between allowed and actual ROEs that is apparent in the frequent occurrence of annual overearnings in contrast to very few years of under earnings.

In the view of the Panel, the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control costs for each test period.

The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.

4.0 CAPITAL STRUCTURE

4.1 Definition of Risk

Dr. Booth has described the most basic definition of risk as "the probability of incurring harm, which in a financial sense means losing money." Ms. McShane agreed with this definition noting that it was consistent with her own testimony which defined risk as the probability that the utility's future returns (including the return on and of capital) will fall short of returns that investors expect and require. Mr. Dall'Antonia put a finer point on it as he described a loss as not earning a fair return or more specifically, a loss is anything that is less than the allowed ROE. (Exhibit B6-12, Dr. Booth Evidence, p. 26; Exhibit B1-15, AMPC 1.4.1; T2:123-124)

The Commission Panel takes no issue with the basic definition of risk as provided by Dr. Booth. However, for this Decision, the Commission Panel views risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognizes the risk of potential financial disruption. We also accept the distinction outlined in both the 2006 Decision and the 2009 Decision where investment risk was described as comprising the sum of business risk, financial risk and regulatory risk.

Both Ms. McShane and Dr. Booth addressed business risk in terms of short-term and long-term risks, a distinction the Commission Panel considers appropriate. Each of these is discussed separately in Sections 4.2 and 4.3.

Dr. Booth has described short run utility risk as the risk of earning a return on capital and long run utility risk as the risk of earning a return of capital. (Exhibit C6-12, p. 25) Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 39) The Commission Panel does not disagree with Ms. McShane but notes that long-term risk, which Ms. McShane outlines as being of primary importance to the utility investor, is primarily reflected in the equity structure determined for FEI considering the investors' ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: "The assessment of risks has

a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

4.2 FEI's Long-Term Risk

In the 2009 Decision, eight factors that influenced FEI's long-term risk were identified. They were:

1. Provincial Government climate and energy policies;
2. The effect of aboriginal rights issues;
3. The competitive position of natural gas relative to electricity;
4. Percentage of new construction being captured by Terasen Gas Inc. (TGI);
5. Natural gas vs. Electricity in high density housing;
6. The impact of Alternative Energy Sources on TGI;
7. Changes in demand related to fuel switching; and
8. Use of natural gas per customer account.

FBCU has stated that the same risk factors are at play in the current proceeding, although they have been expressed and organized somewhat differently. (FBCU Final Submission, pp. 47-48)
For the purposes of examining the long-term risk of FEI, items 4 and 5 related to the capture rate of new construction and the energy choice for high density housing are combined under the more general heading "Customer Growth." Items 7 and 8 related to use per customer and fuel switching related demand are also combined under the new "Market Demand and Throughput" heading. In addition, two new factors which received little or no coverage in the 2009 proceeding are addressed: "Supply Risk" and "Regulatory Risk."

4.2.1 Provincial Government Climate and Energy Policies

In the 2009 Decision, the provincial government climate and energy policies of the previous few years played a significant role. During the period leading up to the proceeding, the provincial government published the "BC 2007 Energy Plan," introduced numerous pieces of legislation (principally in the area of greenhouse gas emissions reduction) and in 2008 implemented the BC Carbon Tax. In the 2009 Decision, the Commission was in agreement with TGI's position that the climate change legislation had created a level of uncertainty which did not exist during the 2005

hearing and stated that the change in government policy "will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity." (2009 Decision, pp. 36-38)

Submissions by Parties

The Commission Panel notes that there is considerable disagreement among the parties concerning the level of risk related to provincial government climate and energy policies. In the current proceeding, FBCU have ranked political risks in the number 2 risk category and submit that the risks associated with policy and legislation are equal to if not greater than in 2009. FBCU note that all of the legislation and policy relied upon by the Commission in the 2009 Decision remains in place and the introduction of the *2010 Clean Energy Act (CEA)* has had the following impacts:

- It has precluded natural gas utilities from using incentives to promote fuel switching (electricity to gas).
- It has required the Commission to account for enumerated energy objectives in the course of considering certain types of applications.

(FBCU Final Submission, pp. 53-56)

Both BCPSO and AMPC/CEC submit that conditions are far more favourable today and the resulting political risks are much lower today than TGI portrayed in 2009. In support of these submissions, they point to a number of factors:

- the lack of plans to increase the carbon tax;
- the introduction of the BC Natural Gas Strategy and its support of natural gas as a transportation fuel; and
- a collapse of the Western Climate Initiative and lack of progress on emissions-trading initiatives.

(BCPSO Final Submission, pp. 15-16; AMPC Final Submission, pp. 22-23)

Commission Determination

The Commission Panel finds that the risks related to provincial government climate and energy policy are less significant when compared to the period leading up to the 2009 Decision. At the time of the 2009 proceeding, there was considerable concern and uncertainty related to provincial

energy policies, how they would be shaped in the future and what impact this would have on Terasen's gas utilities. In addition, the Commission placed importance on the Nyboer Report as reflected in the following statement:

> "In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers." (2009 Decision, p. 37)

The Commission Panel does not consider the current environment to be as threatening to FEI as it was perceived to be in the period leading to the 2009 Decision. As BCPSO points out, there are no plans to raise the carbon tax beyond the current $1.50 per GJ level and as AMPC/CEC reports, the Western Climate Initiative has collapsed and emission trading has become a dormant issue. These all reflect a less threatening current environment and with it, a lessening of risk associated with provincial government climate and energy policies.

4.2.2 Aboriginal Rights

In the 2009 Decision, the Commission Panel acknowledged that risks posed by First Nations did not exist previously and to the extent that they were currently perceived, represented an increase in risk over natural gas local distribution companies operating in other provinces. However, the Commission did not consider that risks posed by First Nations cast doubt over Terasen Gas Inc.'s "ability to earn a return on or of its capital." (2009 Decision, p. 37)

Submissions by Parties

FBCU acknowledge that aboriginal rights issues, which they rank in category 2, are much the same now as they were in 2009 and note that this issue was not addressed by the parties in IRs or at the hearing. (FBCU Final Submission, p. 49)

BCPSO argue the amount of aboriginal rights risk should be reduced relative to 2009, given the FBCU experience and understanding of aboriginal rights and title claims resulting from First Nation consultations tied into CPCN Applications. (BCPSO Final Submission, p. 17)

AMPC/CEC submit that this risk remains unchanged from 2009 where it was given no weight and this remains appropriate. (AMPC/CEC Final Submission, p. 24)

Commission Determination

The Commission Panel agrees with the FBCU and AMPC/CEC and find that there is no evidence to suggest that there has been a significant change to risk associated with aboriginal rights based on the evidentiary record of this proceeding. We also concur with the 2009 Decision that the risk associated with aboriginal rights has little impact on the FEI's ability to earn a return.

4.2.3 Competitive Position of Natural Gas Relative to Electricity

The competitive position of natural gas to electricity is an existing risk which bears scrutiny at each cost of capital proceeding. In the 2009 Decision, the Commission Panel took note of the interveners' position that the risk related to the competitive price of natural gas and electricity had diminished since 2005. However, the Panel considered that the competitive edge which existed was dependent on too many significant variables to be considered permanent. (2009 Decision, p. 36)

Submissions by Parties

The FBCU acknowledge that natural gas prices have fallen but submit that this occurred prior to the 2009 Decision and take no issue with the fact that the development of shale gas is a "game changer" or that there has been an increase in electricity prices. They do take issue with Dr. Booth's conclusion that long-term business risk has declined since 2009 and argue that his reliance on considerations related to cost-effectiveness paints an incomplete, distorted view of FEI's overall competitive position. FBCU make the following arguments in support of their position:

- Natural gas prices fell substantially prior to the 2009 hearing due to shale gas development and this was reflected in the evidentiary record leading to the 2009 Decision.
- Volatility in natural gas prices affect natural gas to electricity competitiveness and has increased due to the suspension of hedging instrument tools resulting from the 2011 Price

Risk Management Decision (PRMP Decision).[5] Looking ahead to 2017 there is a wide potential price range for natural gas based on the AECO Forward Curve. (see Figure 2 below)

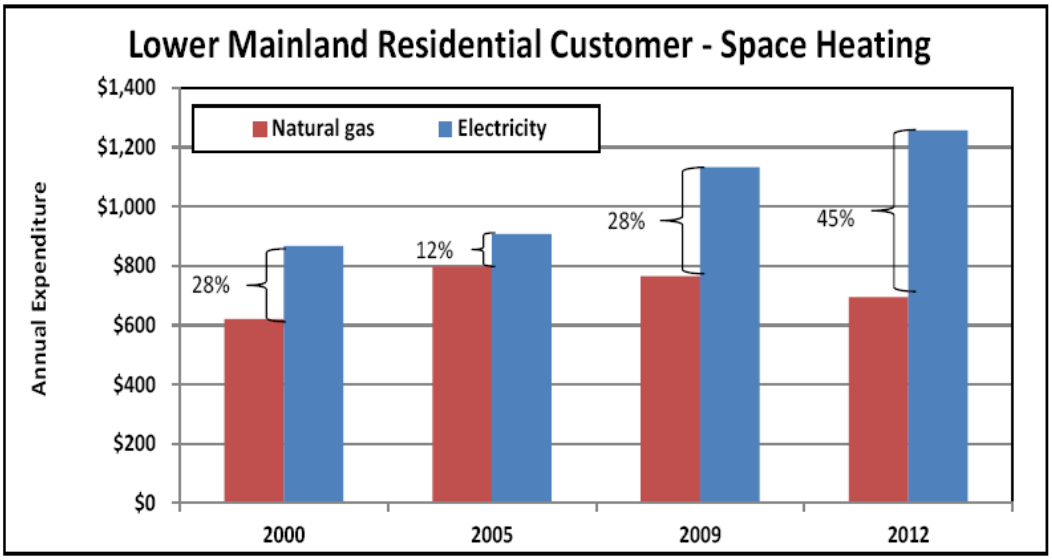
- The price of the natural gas commodity has decreased but the delivered cost of natural gas remains almost the same as 2009.
- Higher capital costs for natural gas heating materially diminish the operating cost advantage of natural gas over electricity.
- Non-price factors such as the desire to create a smaller carbon footprint have resulted in more customers being willing to adopt lower carbon and renewable energy sources.

(FBCU Final Submission, pp. 57-71)

ICG, relying on Figure 1 below, argues that there has been a significant improvement with respect to cost competitiveness between natural gas and electricity since both the 2005 and the 2009 proceedings.

Figure 1: Estimated Annual Expenditure

Figure 1: Estimated Annual Expenditure for FEI Lower Mainland Residential Customer – Natural Gas and Electricity for Space Heating

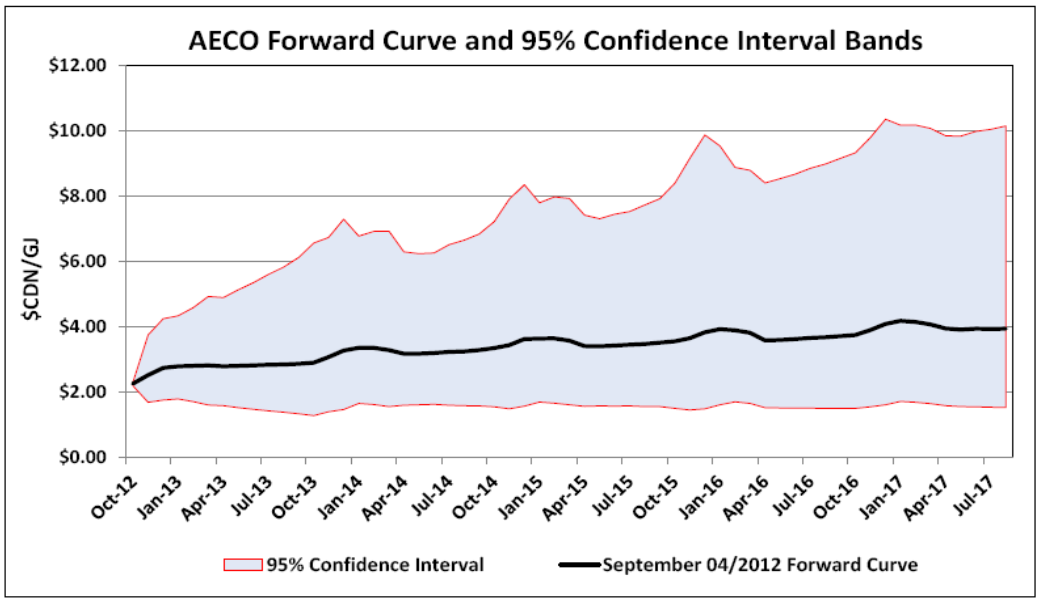


(Source: Exhibit B1-11, FBCU Response to BC Utility Customers, 1.4.2)

ICG contends that shale gas has been a game changer for natural gas prices, which has resulted in a "seismic" shift in the competitiveness of natural gas versus electricity. (ICG Final Submission, p. 11)

[5] Order G-163-11

Figure 2: AECO Forward Curve



(Source: Exhibit B1-20, BCUC 1.105.1)

BCPSO notes that there has been no change in FBCU's rating of capital cost and it is the same as in 2009. It argues there is no evidence that the effect of higher capital costs will offset any competitive gain made through lower commodity prices. Further, BCPSO submits that the AECO Forward Curve relied upon by FBCU demonstrates only an increasing level of price uncertainty over time, not volatility. BCPSO also takes issue with the FBCU claim that there is effectively no reduction in the customers overall bill. The important comparison is not natural gas against itself but against electricity, and this comparison is very favourable to FEI. (BCPSO Final Submission, pp. 9-10)

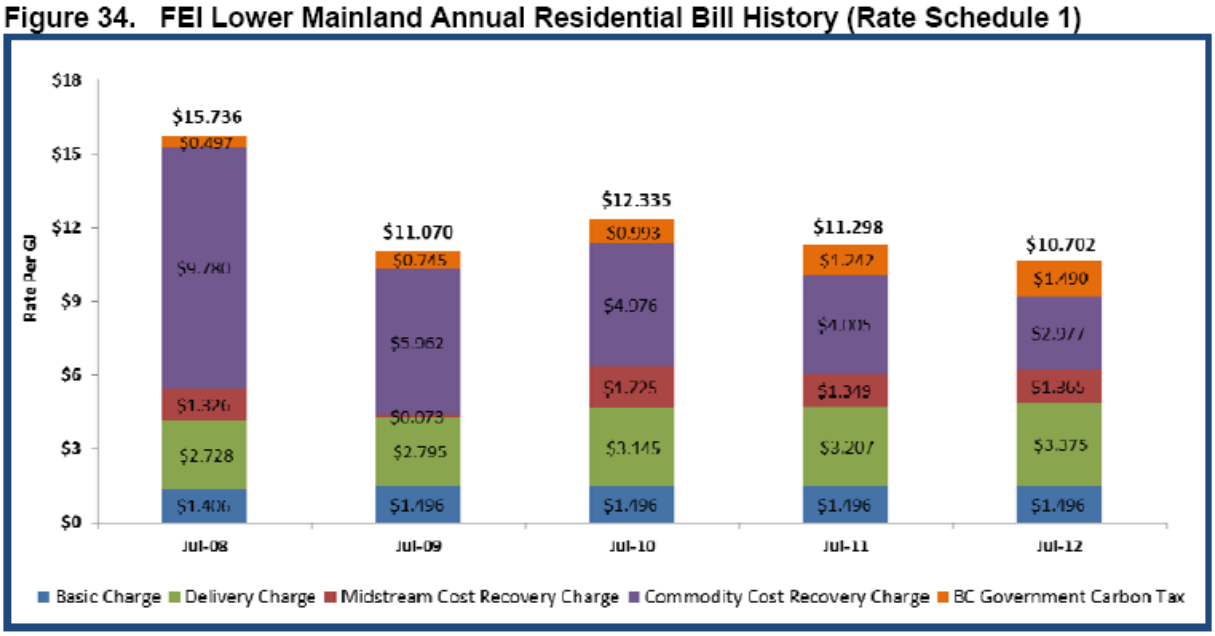
AMPC/CEC state that price is a key determinant of natural gas competitiveness and deserves the greatest weight when considering changes to FEI's business risk. In answer to FBCU's claim that the delivered cost of natural gas is similar to 2009, AMPC/CEC argue that prices are at or near a ten-year low and by FBCU's evidence (in Figure 3 below) are lower than 2009 and even more so when compared against 2005. (AMPC/CEC Final Submission, pp. 11-13)

AMPC/CEC assert that the volatility is manageable through options, including equal payment plans and deferral accounts which FEI currently uses. AMPC/CEC notes than in addition to these options, FEI is proactive in communicating the natural gas cost advantage relative to other sources.

AMPC/CEC also submit that a telling point with regard to competitiveness is how it compares to electricity. They assert that FBCU's response to AMPC/CEC 1.4.2 (Exhibit B1-15) outlines the savings of natural gas over electricity for space heating (and to a lesser extent water heating) and demonstrates a trend that continues to widen. In their view, this information demonstrates that FEI is the beneficiary of both a reduction in gas prices and rising BC Hydro rates. (AMPC/CEC Final Submission, pp. 11-16)

In Reply, FBCU argue that using November 2009 rather than July 2009 is a more appropriate point of comparison and represents a variance of less than 3 percent. They also point out that this difference has been insufficient to drive behavioral changes in new and existing customers. (FBCU Reply, p. 14)

Figure 3: Delivered Cost of Natural Gas



(Source: Revised Exhibit B1-9-6, Appendix H, p. 51, Figure 34)

Additionally, FBCU state that they have not suggested that there is an increase in price volatility, but rather they have fewer tools to deal with it. Overall, FBCU submit that commodity price volatility is a risk factor which remains undiminished since 2009. (FBCU Reply, pp. 14-15)

Commission Determination

The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk. **The Commission Panel finds that there has been some reduction in the level of risk associated with the competitive position of natural gas as compared to electricity.** It is difficult to reach any other conclusion given there has been a reduction in the total billing costs while over the same period the cost of electricity has risen regardless of the timeline one chooses for comparison. The evidence relied upon by the interveners in Figure 1, which details the growing variance between natural gas and electricity, is persuasive and it is unlikely that a price conscious customer would move away from natural gas in these circumstances. Looking ahead, and relying upon the information in Figure 2 above, the Panel notes that in spite of the range considered to fall under the 95 percent interval band, the September 4, 2012 AECO Forward Curve projects relatively stable natural gas commodity costs looking out to 2017. While hardly definitive, this does point to some level of stability over the next few years.

Notwithstanding these favourable conditions, the Commission Panel does place some weight on the lack of change in the purchasing behaviour of new and existing customers. In our view, some of this relates to the higher capital costs required to convert to or install natural gas service and the move to multi-family dwellings, which is discussed in Section 4.2.4.

FBCU state that price volatility is a risk factor that remains undiminished since 2009. Based on the evidentiary record we agree. However, we are not in agreement with the assertion that FEI have fewer tools to manage volatility. In the PRMP Decision, the Commission Panel offered a number of suggestions or options FEI may wish to consider. Included among these was offering the PRMP program to existing customers on a permission basis. There is no evidence before the Panel to indicate any action that FBCU has taken to bring alternatives forward.

4.2.4 Customer Growth

Submissions by Parties

FBCU note that a continuing trend has been its lower capture rate on new construction and reports a decline in the rate of net residential customer additions when 2011 is compared against 2007. In addition, the FBCU submits that new customer usage is roughly half what it used to be and therefore, the trend that existed in 2009 has not changed. FBCU states that this trend is closely associated with growth of multi-family dwellings in BC, a market where FEI has low penetration driven by unfavourable installation economics. This shift toward multi-family dwellings means that FEI's capture rate will further decline over time. (FBCU Final Submission, pp. 50-51; Exhibit B1-9, Appendix H, pp. 33-37)

AMPC/CEC point out that in spite of the challenges faced by FEI in growing customers, its total customer base continues to grow. The number of residential customers grew by 8 percent over the period 2005-2011 and the number of commercial customers grew by 5 percent over the same period while there was some decline in the number if not the consumption of industrial customers. (AMPC/CEC Final Submission, pp. 16; Exhibit B1-11, BCUC 1.4.4)

Commission Determination

The Commission Panel notes that the circumstances related to unfavourable installation economics and the shift toward multi-family dwellings existed at the time of the 2009 Decision. In spite of this, the total number of customers continues to grow if not the market share of potential new customers. **Therefore, the Commission Panel finds that there is no persuasive evidence to suggest there has been a shift in risk related to customer growth.**

4.2.5 Impact of Alternate Energy Services on FEI

Submissions by Parties

FBCU state that the "adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business for providing natural gas for space and water heating." The recent number of energy projects approved serves to demonstrate the momentum behind

alternative energy which FBCU rate in the number 2 risk category. In FBCU's view, the growing consumer awareness of alternative energy and its green attributes and increasing cost effectiveness demonstrate the importance of this risk factor for FEI. (FBCU Final Submission, p. 52; Exhibit B1-9, Appendix H, p. 28)

AMPC/CEC argue that this represents double counting and there is no evidence to suggest that there is more risk posed by alternative energy to FEI than that which existed in 2009. Further, they argue that the new transportation technology will result in improved prospects as it allows natural gas to replace diesel in heavy trucking thereby increasing natural gas demand in the future. (AMPC/CEC Final Submission, p. 18)

Commission Determination

The Commission Panel notes that the impact of AES sources on FEI is not a new risk. However, we do acknowledge that in the three years since the 2009 proceeding, there has been greater momentum behind alternative energy forms and the adoption of new technology related to them. Therefore, the Panel is mindful that there is the potential for an increase in risk related to AES but, given that much of this risk has been accounted for in reference to FBCU's share of multi-family dwellings, it is difficult to quantify.

4.2.6 Market Demand and Throughput

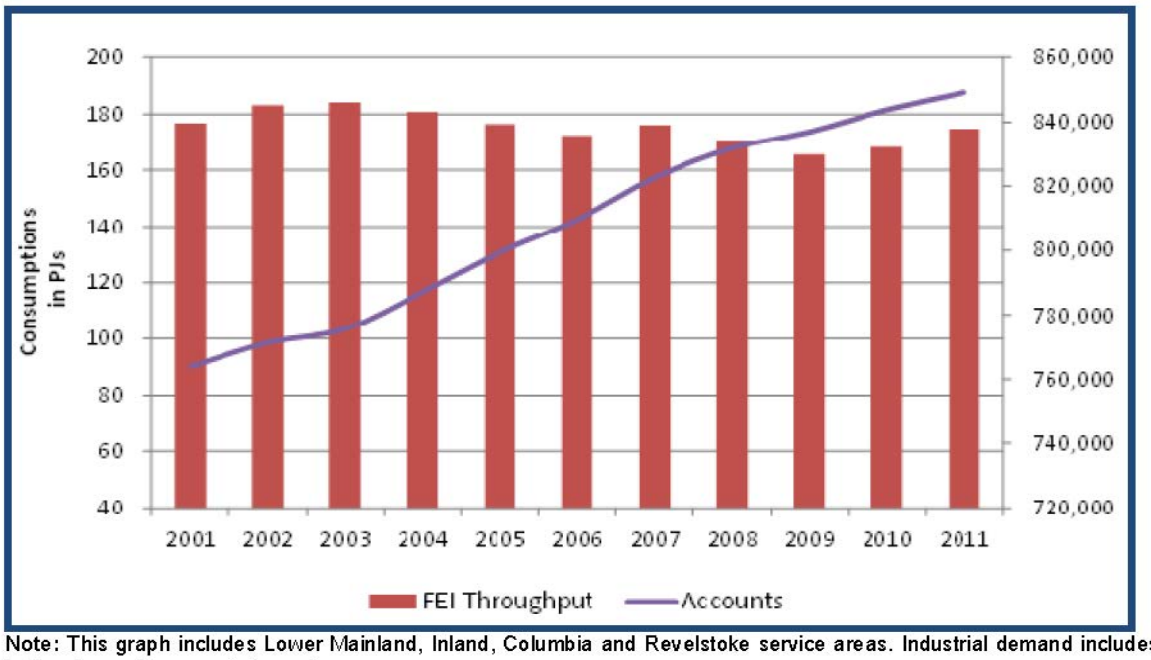
Submissions by Parties

The FBCU state that FEI's use per customer (UPC) for both new and existing customers has been declining; this trend, based on a Conservation Potential Review Study, is expected to continue until 2030. Contributing to this decline are a variety of factors including technological advances and energy efficiency improvements. In addition, the decline in UPC can, in part, be attributed to increased efficiency standards, better building envelopes and a move to smaller dwellings. Further, FBCU state that new construction research since the 2009 hearing shows that natural gas has been increasingly used as a secondary fuel source in new homes rather than the primary source. The FBCU state that there is no reason to believe the drivers behind these market trends will cease. (FBCU Final Submission, pp. 52-53; Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

ICG states that Exhibit B1-41 shows that there has been no decline in system throughput since 2009. In addition, ICG asserts that there is an upward trend in industrial throughput, which is reflective of lower natural gas prices over the same period. Given this recent trend, ICG argues that the Commission should not accept the FBCU's 2013-2016 lower industrial throughput evidence and conclude that business risks are in fact lower than in 2009. (Exhibit B1-41, Undertaking No. 6, p. 3; ICG Final Submission, pp. 7-9)

BCPSO notes that the Commission acknowledged the risks related to throughput in its 2009 Decision and, as a result, they are not new. BCPSO, like AMPC/CEC, further submit that based on graphical information in Figure 4 below, the trend of declining throughput has reversed itself in 2009 and has increased each year since. (BCPSO Final Submission, pp. 13-14)

Figure 4: FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



Note: This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

(Source: Exhibit B1-9-6, Section H, p. 9)

AMPC/CEC submit that the evidence presented by FBCU shows that both commercial and industrial UPC has increased since 2009, while residential UPC has decreased only marginally.

AMPC/CEC further submit that as the Commission considers the issue of declining UPC, it should consider two points:

- The residential throughput would have to decrease by 83 percent in 2012 to drive its distribution margin to a level equal to BC Hydro Tier 2 Rates; and
- The negative trend related to the creation of energy efficiency is no different than that faced by BC Hydro.

AMPC/CEC argues that these energy trends are not new and there is only risk if they affect the utility's ability to earn a fair return which, in their view, is not supported by the evidence on the record. (AMPC/CEC Final Submission, pp. 16-18)

In Reply, FBCU submit that revenues related to increased throughput are largely unaffected due to the structure of industrial contracts that only generate additional revenue if consumption exceeds an agreed upon level. Therefore, the declines in residential and commercial UPC continue to have a disproportionate impact on FEI. FBCU also point out that AMPC/CEC's reliance on Tier 2 rates is inappropriate. In addition, they argue that the AMPC/CEC's position is based on the view that existing customers will not leave natural gas until there is no longer a price advantage. FBCU state that this assumption is unwarranted given recent research that people are less committed to natural gas, irrespective of price. (FBCU Reply, pp. 16-17)

Commission Determination

The Commission Panel finds that there is insufficient evidence to support a finding that there has been a shift in risk related to market demand and throughput.

The Commission Panel notes that the decline in UPC and overall throughput were issues raised in the 2009 proceeding. Based on the evidence in this proceeding, it is apparent that the overall throughput has increased since 2009 and UPC, while decreasing overall, has increased for both commercial and industrial customers. In the view of the Panel, these are all positive but not conclusive signs.

The Commission Panel places little weight on the FBCU submission that the increased throughput has not resulted in increased revenue due to the structure of industrial contracts. Notwithstanding our understanding that industrial contracts are subject to competitive negotiations, in our view, FBCU nonetheless has some control over the structure of and risks related to the contracts it negotiates.

The Commission Panel does not consider the research indicating existing customers are less committed to natural gas in spite of the price advantage to be persuasive. The Panel notes that much of the research referred to in this context was related to AES options, which have been considered as part of the growth of multi-family dwellings addressed in Section 4.2.4. (Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

4.2.7 Supply Risk

Submissions by Parties

FBCU's position is that BC's shale deposits do not guarantee a reliable supply of natural gas at reasonable prices. Due to the higher cost of development relative to other areas and a lack of infrastructure for resource development and market connection, FBCU state that growth of production in northeastern BC has stopped and there is risk of current levels declining. This is in contrast to developments like the Marcellus Formation in the northeast part of the continent that is thriving. FBCU submit that this leads to the possibility of stranded resources or, at a minimum, higher market prices and an expansion of access infrastructure to encourage expansion of BC's shale gas resources.

FBCU also submit there is a lack of new development of infrastructure to move gas to FEI's service territory. They argue that the development of gas transmission infrastructure projects connecting BC sources with Alberta and Eastern markets, combined with the potential for LNG exports, could change the historical pricing relationship between BC supply and Alberta production leading to higher consumer prices in the future. (FBCU Final Submission, pp. 60-61)

AMPC/CEC describe the potential for stranded resources in northwestern BC as nonsensical. They submit that the impact of shale gas development on prices was not recognized, as it was not mentioned in the 2009 Decision. They also refer to the following statement of Ms. Des Brisay in the current proceeding:

> "What was not fully understood is how low the cost could be in terms of how we produced that resource, and that's really where we have seen the shifting of the curve has been as we have a better understanding of the economic feasibility of the development of shale gas reserves in different parts of North America." (T2:161)

Therefore, AMPC/CEC argues the existence of reserves may have been known in 2009, but the understanding of the economic feasibility of development has shifted since then. (AMPC/CEC Final Submission, p. 19)

AMPC/CEC submit that any weight the security of supply factor deserves pales when compared to the availability of supply. The Commission Panel notes they did not comment directly on the potential change to the historic pricing relationship between Alberta and BC. (AMPC/CEC Final Submission, pp. 18-20)

As noted previously, FBCU acknowledge that shale gas has been a "game changer" and that supply risk has declined. They did make the following points:

- There was knowledge of natural gas reserves prior to the 2009 proceeding.
- The price of natural gas must be higher (leading to higher rates) before supply will be extracted.
- FEI's ability to access cost effective supply could be challenged as there are competing markets for natural gas.

FBCU argue that it is the factors affecting demand for delivered natural gas, not energy supply considerations, that are the key supply risk for FEI. (FBCU Reply, pp. 19-20)

Commission Determination

The Commission Panel finds that there has been a decrease in the risk associated with the supply of gas but an increase in the risk associated with access to this gas at low prices. Balancing the two, there has been no material change in the level of risk related to energy supply.

The Commission Panel accepts the statement of Ms. Des Brisay as informative and a reasonably accurate reflection of where matters stood at the time leading up to the 2009 Decision. There is clearly no disagreement among the parties with respect to the existence of adequate supply of natural gas and FBCU have conceded that the actual supply risk has declined. Therefore, the issue is not whether natural gas will be available but whether sufficient natural gas will be available at the low commodity price levels that the consumer has come to expect. To this end, FBCU have laid out a number of facts and potential scenarios which they argue will have a significant impact on the supply of low cost natural gas. None of the interveners have challenged this information except AMPC/CEC who characterized the potential stranding of assets as "ludicrous."

In our view, the potential for some of FBCU's concerns to become a reality cannot be dismissed. The stability of the current environment remains uncertain, as does the magnitude of future development of the LNG business. Until this has been determined, the continuity of current low price levels for natural gas will be at some risk. However, the risk of supply to the extent that it existed, has abated and shifted to the risk associated with maintaining existing commodity price levels with no resulting increase in overall risk.

4.2.8 Regulatory Risk

Submissions by Parties

FBCU has ranked regulatory risk as their highest risk area with a number of factors in the "higher risk" category. In assigning this weighting, FBCU states that FEI is dependent on regulatory approvals that determine its revenue requirements, cost of service recovery and approval of investments. FBCU submit that the pace of change in the energy policy and environment has

increased at a time when the Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment and added process as compared to 2009. (Exhibit B1-9-1, Section H, pp. 5-6)

BCPSO points out the FBCU witnesses have confirmed that the regulatory environment is predictable and stable and regulatory risk should not be viewed as its number one risk factor. (BCPSO Final Submission, pp. 14-15)

AMPC/CEC questions the FBCU ranking of regulatory risk as there is no compelling evidence to suggest that FEI faces greater regulatory uncertainty than it did in 2009. (AMPC/CEC Final Submission, pp. 10, 20)

In Reply, FBCU acknowledge that the relative stability and predictability of the BC regulatory framework reduces regulatory risk. However, they point out that the breadth of the Commission's influence on FEI's business is undeniable and individual decisions can have significant implications for FEI particularly in the short-term. While they identify "regulatory risk as being 'higher,' any change since 2009 was not material to FEI's overall risk." (FBCU Reply, p. 12)

Commission Determination

The Commission Panel finds that there has been no material change in the level of risk associated with regulatory risk.

The Commission Panel accepts that the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI. However, we agree with the parties that argue there has not been a material change since the 2009 Decision.

4.3 FEI's Short-Term Risk

There are two issues that must be considered by the Commission Panel with respect to short-term risk. The first is whether there has been a change in short-term risk since the 2009 Decision. The second is how much of FEI's short-term risk has been mitigated and, as a result, how much of the remaining risk must be considered. In the view of the Commission Panel, this will be determinative

as to the level of weight to be placed upon the short-term risk in this proceeding. FBCU has expressed disagreement with the need to determine the level of short-term risk in reply to BCSPO submissions:

> "The Commission need not attempt to characterize or quantify FEI's short-term risk to determine a fair return for FEI. The question requiring a determination is the extent to which FEI's short-term risk has changed since 2009." (FBCU Reply, p. 9)

The Commission Panel disagrees. There are many measures of risk. The overall level of risk may not have changed substantially but one needs to consider the individual risk elements and their weighting. These may have changed and therefore, not considering them may be a mistake.

4.3.1 Change in Short-Term Risk

Submissions by Parties

The FBCU submit that short-term risk is essentially the same as in 2009. (FBCU Final Submission, p. 45)

Both FBCU and the interveners have focused their submissions on two areas in examining short-term risk:

- FEI's record of generally being able to earn its allowed ROE; and
- The amount of risk mitigation provided by deferral accounts.

Matters related to FEI's history of typically earning its ROE were dealt with in Section 3.3, where it was determined that actual earnings versus approved earnings history is more appropriately a matter for consideration in revenue requirements proceedings.

Concerning the use of deferral accounts, FBCU submit that "FEI's ability to manage short-term risk with deferral accounts is a function of the portion of the overall revenue requirement covered by deferrals, irrespective of the number of accounts providing that coverage." They also submit that there has been no material change in the collective scope of deferrals having an effect on earnings

volatility. In the view of FBCU, their evidence on deferral accounts shows that the percentage of revenue requirements covered by deferral accounts has decreased and has resulted in a credit to customers. (FBCU Final Submission, pp. 38-45)

AMPC/CEC acknowledge that some of the additions in deferral accounts since 2009 are a reflection of accounting changes, but submit that three new accounts (Compliance to Emission Regulation Account, Customer Service Variance Account and Depreciation Variance Account) are significant. They further submit that while the new accounts may not represent a monumental change, they are an indication of FEI's ability to obtain such accounts. Therefore, this risk factor is lower today than in 2009. (AMPC/CEC Final Submission, p. 22)

BCPSO agrees with the submissions of AMPC/CEC and submits that the addition of the three new accounts demonstrates the Commission's willingness to mitigate the impact of short-term uncertainties. It concludes that the new accounts indicate short-term risk is no greater and likely less. In sum, BCPSO submit that short-term business risk is lower than in 2009. (BCPSO Final Submission, pp. 8-9)

FBCU, in reply, assert that the submissions of AMPC/CEC are at odds with the evidence of their witness, Dr. Booth, "who admitted that FEI risk hadn't changed "in the slightest."" The Commission Panel notes that Dr. Booth (T8:1475) was referring to ROE and not overall risk. FBCU conclude that short-term risk when compared to risk faced by its peers in other jurisdictions, remains unchanged. (FBCU Reply, p. 9)

Commission Determination

The Commission Panel, after reviewing the evidence, finds that there has not been a material change to FEI's short-term risk since the 2009 Decision. However, to the extent that there have been additional deferral accounts added, there is a greater ability to mitigate short-term risk. The Commission Panel agrees with BCPSO that the Commission's approval of the new deferral accounts demonstrates a willingness on the part of the Commission to mitigate the impact of uncertainty. However, in the Panel's view it is not important how the deferral account came to be. It is the

effect. Therefore, the fact that the Depreciation Variance Account was ordered by the Commission, as noted by FBCU, in our view, is immaterial. More important is the fact that the deferral account now exists, as it reduces the risk associated with unforeseen variances in depreciation amounts.

4.3.2 Magnitude of Short-Term Risk

The second question to be considered by the Commission Panel with respect to short-term risk relates to the level of mitigation which has or could be applied against short-term risk. Much of the evidence related to this was focused on the use of deferral accounts which we explore below.

Revenue Related Deferral Accounts

The FBCU consider the overall risk for residential and commercial sales to be moderate and have assessed the risk of industrial sales to be high.

In 2011, residential and commercial sales accounted for 87.9 percent or $485.4 million of the total delivery margin revenue of $552.3 million. FBCU are protected for changes in use per customer for residential and commercial sales through the Rate Stabilization Adjustment Mechanism (RSAM). In assessing these risks as moderate, FBCU point out they are not protected for any differences in actual and forecast number of new customers in a given test period. The Commission Panel notes that impact of any variance in customer additions is likely to be minor, given the relatively small number of new customer additions as a function of the existing customer base. **Given the relatively heavy reliance on existing customers for most of the revenue and the existence of the RSAM, the Commission Panel finds the short-term risk related to residential and commercial sales to be low rather than moderate as suggested by FBCU.**

Industrial sales account for 12.1 percent or $66.8 million of the delivery margin revenue in 2011. FBCU assess the risk as high in this area because there are no deferral accounts utilized with this customer group. (Exhibit B1-20, BCUC 1.96.1)

In reviewing the submissions, the Commission Panel notes the following statement made by FBCU in reply to AMPC/CEC submissions: "Increased consumption by industrial customers only generates additional revenue if the consumption **exceeds a customer's fixed contract demand** (i.e., the 'take

or pay' volume)." [emphasis added] Notwithstanding the impact on revenue as addressed in this statement, it appears to the Panel that the lack of deferral accounts in the industrial category is because there is no need as this area is run on a contract basis with a reliance on "take or pay" contracts. (FBCU Reply, p. 16) It is therefore evident that potential risk is mitigated to a large extend by the existence of such contracts. **For these reasons, the Commission Panel finds that a "high" risk rating for industrial sales is inappropriate and a moderate to low rating is more appropriate to the level of risk.**

Expense Related Deferral Accounts

Table 1 of the FBCU response to BCUC IR 1.96.1.1 indicates that in 2011, 75.3 percent ($1,160.7 million) of the FEI revenue requirement or 31.0 percent ($171.1 million) of the Revenue Margin Delivery Requirement was covered by way of deferral accounts. Overall, the single biggest expense item was cost of gas, which at $989.6 million is 100 percent covered by deferral mechanisms.

FBCU's Operation and Maintenance (O&M) Expense totalled $184.6 million. Of this, approximately 9 percent encompassing Pension & OPEB Variance, Insurance Variance and BCUC Levies Variance Deferral is covered by deferral accounts. FBCU rates the overall risk of O&M Expense as high citing the small portion covered by deferral accounts in explanation.

The Commission Panel also notes that of the remaining revenue requirements categories, Property and Sundry Taxes ($50.2 million), Financing Costs ($108.5 million) and Depreciation and Amortization ($99.9 million) are at or near 100 percent deferral account protection levels. (Exhibit B1-24, BCUC 2.182.1; Exhibit B1-20, BCUC 1.96.1)

The most significant area not covered to a large degree by deferral accounts is O&M Expenses. O&M Expenses are also an area where there is a history of under spending approved O&M amounts. Under cross-examination, Mr. Dall'Antonia explained that risks at the start of each test year are the same and the success of managing within budgets can be attributed to management's experience and being sound managers. (T3:344) While the Commission Panel does not take issue with Mr. Dall'Antonia's comments, we are of the view that in addition to this, FEI has a broad range of options available to it to manage O&M budgets effectively. For example, many of the initiatives in an approved O&M plan can be postponed for short periods or in some cases not implemented

within the test period. This could include items such as routine maintenance, new staff additions, replacement of staff vacancies or delaying of new programs or initiatives. This may, in part, account for the fact that O&M expenditures were less than forecast in 8 of the last 9 years. (Exhibit B1-24, BCUC 2.182.1) Therefore, in the view of the Commission Panel, this is an area where FEI has a high degree of control. **Accordingly, the Commission Panel finds that a high risk rating for O&M expenses is not appropriate and a moderate to low rating is more reflective of the risk FEI faces.**

Another area with a high risk rating due to limited use of deferral accounts is Other Operating Revenue which encompasses things like late payment charges, NSF cheques, and connection charges. This item has been in the $20 to $25 million range over the last nine years, which is a relatively small part of revenue requirements. However, as outlined in Undertaking No. 8, there have been consistent negative variances (meaning revenues were less than approved) in the $2 million range for all but the most recent completed year. (Exhibit B1-24, BCUC 182.1; Exhibit B1-20, BCUC 1.96.1; T2:293-294; Exhibit B1-43)

The Commission Panel acknowledges that many of the Other Operating Revenue areas are less predictable and controllable in nature and most items are not covered by deferral accounts. Therefore, the Commission Panel finds that a high risk rating is appropriate.

Commission Determination

Given our findings with respect to revenue risks and risks in expense areas not covered by deferral accounts, the Commission Panel is not persuaded that on balance FEI faces significant short-term risks to its achieving its allowed ROE in a given test period. While including items that are less predictable or controllable, the Other Operating Revenue item generally shows a consistent pattern of under earning revenues. However, their impact on the total revenue requirements is relatively small. **Therefore, acknowledging that there has been little change in short-term risk since the 2009 Decision, the Commission Panel has determined that only minimal weight can be given short-term risk as an impediment to earning a fair return.**

4.4 Developing an Optimal Capital Structure

An important component of the Panel's task is to determine an allowed capital structure. This section is devoted to the discussion of the evidence presented that relates to the capital structure decision and presents the Commission Panel's findings. In this section, we set out the context within which this evidence has been considered.

4.4.1 Capital Structure and the Fair Return Standard

Background on the role of capital structure on the cost of capital is provided in the Brattle Report, which recognizes that "underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return." In addition, the result of a specific capital structure is a particular Weighted Average Cost of Capital.

$$WACC = r_d(1 - T_C).\frac{D}{V} + r_E\frac{E}{V}$$

where: r_d = market cost of debt; r_E = market cost of equity; T_C = corporate income tax rate; D = market value of debt; E= market value of equity; and V = the market value of the firm (i.e., V= D+E).

(Exhibit A2-3, pp. 38-40)

This cost of capital reflects the equity risk and the debt risk, both of which in turn reflect both operating and financial risk, as well as the tax advantage of debt.

The integration of the capital structure decision with the ROE decision is recognized in the argument of AMPC/CEC:

> "Capital structure is important for two main reasons: (1) the cost of equity is higher to reflect the greater risk of investing in shares as opposed to bonds, and (2) the cost of debt (interest) is tax deductible, whereas the cost of equity (dividends) is paid out of after-tax income. Consequently, equity is substantially more expensive than debt. . . . FEI's customers have a right to expect that its capital structure will be efficient and the common equity component will reflect the real risks equity shareholders are exposed to." (AMPC/CEC Final Submission, p. 32)

Ms. McShane submits that the inter-dependence between capital structure and ROE is largely based on the FRS with its three requirements i) the ability to attract capital on reasonable terms, ii) maintenance of financial integrity; and iii) comparability of returns. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 34)

These considerations translate into a focus on credit metrics and the need to maintain a particular credit rating. The FBCU does, however, discuss at length the possible disruptions that might take place if FBCU experienced a rating downgrade. AMPC/CEC submit that FBCU's credit metrics are not weak and that a 35 percent common equity ratio (as compared to its existing 40 percent ratio) "is entirely consistent with the objective of maintaining FEI's existing credit rating." (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 35-37; FBCU Final Submission, pp. 12-15; AMPC/CEC Submission, pp. 32, 34-36)

4.4.2 Commission Panel Discussion

The Commission Panel accepts the view put forth by AMPC/CEC that the capital structure should be set efficiently. The Panel also notes that debt comes with advantages, primarily the deductibility of interest payments from taxes.

At the same time, the Commission Panel recognizes the argument made by FBCU that the excessive use of debt could disrupt the operations of the company by making it difficult to finance the ongoing operations.

The Commission Panel accepts, therefore, that there are both expected benefits and expected costs associated with the use of debt. The task faced by the Panel is to determine the 'optimal' capital structure, one that is efficient in reducing the total or WACC through the use of debt without creating potential financing disruptions that could offset these benefits to the point where the net benefit is reduced.

The discussion of the capital structure evidence and determination found in this section reflects the Panel's desire to find an efficient or optimal capital structure. In doing so it applies the following principles to guide its analysis:

1. While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of the attendant costs and benefits.
2. The long-run risks discussed by all parties are important considerations in determining an optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management. Since the concern is with financial disruption, both diversifiable and non-diversifiable risks must be recognized in assessing the risk of financial disruption.
3. The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility. It is in this sense that the Panel agrees with FBCU's view that FEI is not a diversified investor. (FBCU Final Submission, pp. 130-131) As discussed in Section 5, however, this does not imply that the Panel accepts this view with regard to the ROE.

4.5 Credit Ratings and Metrics

An important issue for the Commission Panel is to determine how important it is for FEI, as the benchmark utility, to maintain an "A" category credit rating among credit agencies. Credit ratings are important indicators of potential financial disruption as discussed in Section 4.4. A lowering of credit agency ratings raises concerns about the cost of debt and access to the credit market at reasonable cost. Therefore, there are clearly advantages of maintaining an ROE and capital structure which will allow for existing credit agency ratings to be maintained. However, the Commission Panel must consider whether there is a point where maintenance of a particular credit rating may result in a capital structure or ROE that is suboptimal in the circumstances. In such instances, what importance should the Commission Panel place on the maintenance of a credit rating and at what additional cost?

Presently, FEI is rated by Moody's and DBRS, with Moody's providing the lower credit rating at A3, which is just one level above a Baa rating. DBRS provides a slightly higher A rating, which is comparable to a Moody's A2 rating. (Exhibit B1-58) The Moody's rating is considered to be more vulnerable to a downgrade due to weaker credit metrics, which, with further deterioration and a less predictable and supportive regulatory environment, could result in a drop to the Baa rating. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 59) This Baa rating could reduce the financial integrity of FEI by reducing its ability to maintain credit and access capital on as reasonable terms as an A3 rating.

The Commission determined in the 2009 Decision that Moody's rating should be the focus of attention because it was the lower in the group, and that the Moody's A3 rating should be maintained with a margin of cushion to ensure the financial integrity of FEI. (2009 Decision, p. 15)

None of the interveners took the position that FEI's 'A' rating should be jeopardized. AMPC/CEC submit that a reduction of the ROE to 7.5 percent at the existing 40 percent equity ratio would still leave FEI with strong credit metrics, including a cash flow coverage ratio of 2.67, and that a combined ROE reduction to 7.5 percent and lower equity ratio to 35 percent would leave FEI with a 2.35 ratio, which would still be above Moody's stated threshold of 2.3 to maintain the A3 rating. (AMPC/CEC Final Submission, pp. 35-36)

FBCU state that their current credit metrics are already weak for the existing rating and that the combined reduction in ROE and equity ratio as suggested by AMPC/CEC would not allow it to have a margin of comfort. (FBCU Final Submission, p. 15) FBCU also state that Moody's assessment of regulatory support had already weakened because of BC provincial energy policy. (T3:366) FBCU further state that under the Trust Indenture, Dr. Booth's recommendation would result in a coverage ratio of approximately 1.97. (FBCU Final Submission, p. 77)

Ms. McShane noted that the importance of 'A' category credit ratings arises from two factors: market access and cost. With respect to market access, Ms. McShane testified that regulated issuers can at times be closed out of the market if they have less than an 'A' category rating. Ms McShane further testified that "during the period June 2008 to January 2009, there was not a single issuer without at least one "A" credit rating who was able to issue long term debt <u>on any terms</u> in the Canadian market." With respect to cost, Ms. McShane states that in addition to market access issues, a rating downgrade would result in a cost increase to additional debt the company needs to raise. Further, it will also affect all of the utilities' outstanding debt as the increased cost of new debt will increase the required yield on existing debt and reduce the value of that debt. This higher cost of debt to the utility results in a higher cost of debt for ratepayers.
Ms. McShane further submits that institutional investors continue to have limits upon the amount of 'sub A' category debt they are able to hold or are restricted from holding Baa/BBB debt at all. This underscores the importance of 'A' credit ratings given the relatively small size of the Canadian market for Baa/BBB debt. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 35-37)

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36**)**

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

4.6 Other Jurisdictions

There is general agreement among the parties that the major natural gas utilities in Canada should serve as comparables for FEI for the purposes of assessing FEI's capital structure. This group which includes ATCO Gas, Union Gas, Enbridge Gas Distribution and Gaz Metro was used extensively throughout the proceeding as comparators. Dr. Booth also identified Nova Scotia Power Inc. as a reasonable comparator, being a province-wide integrated electric utility.

The equity thickness ratios of the comparator group of utilities are listed below in Figure 5. The equity ratios of the Canadian comparator group range from 36 percent to 39 percent in contrast to Dr. Booth's recommended equity ratio of 35 percent and FEI's current equity ratio of 40 percent:

Figure 5: Canadian Comparative Utility Equity Ratios

Company	Equity Ratio (%)
FEI	40.00
Dr. Booth on FEI	35.00
ATCO	39.00
Union Gas	36.00
Enbridge Gas Distribution	36.00
Gaz Métro *(*Quebec)*	38.50

(Source: FBCU Final Submission, p. 78)

While there is common agreement as to comparable gas utilities, there is considerable disagreement among the parties as to what these comparables suggest about FEI's required common equity ratio. (FBCU Final Submission, p. 78)

4.6.1 FEI Risk Level Relative to Alberta and Ontario Utilities

FBCU submit that the Commission should find that FEI faces higher long-term risk than natural gas distribution utilities in Alberta and Ontario for the following reasons:

- Alberta and Ontario marketplaces are more favourable from the perspective of supply and infrastructure for natural gas, overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the regions, and overall gas flows;
- Electricity costs in Alberta and Ontario are not heavily influenced by low embedded costs of "heritage hydroelectricity;"
- Eastern based utilities, by virtue of their proximity to the Marcellus Formation, have seen greater benefits from shale gas than FEI;
- The growing prevalence of multi-family dwellings in BC. The FBCU note that in a hearing before the Alberta Utilities Commission in 2011, Dr. Booth described this "condification" as a "significant competitive pressure;" and
- Government policy and legislation is a long-term risk factor for FEI. Among the provinces, BC is at the forefront of GHG reduction initiatives.

  (FBCU Final Submission, pp. 77-81)

FBCU point out that regardless of the analysis relied upon by Dr. Booth, his approach ended up recommending a 35 percent common equity ratio for all Canadian Utilities excepting Gaz Metro. (Exhibit C6-12, AMPC/CEC Evidence, Dr. Booth Evidence, p. 43) In this instance, FBCU had the following concerns with the analysis leading to his recommendation of 35 percent:

- Absent from the comparison was ATCO Gas which was the highest comparator at a 39 percent common equity ratio. FBCU notes that Dr. Booth puts ATCO Gas in the same risk category as FEI and perhaps a little riskier.
- There was no reference to Gaz Metro's deemed preferred shares in his portraying them as having a common equity ratio of 38.5 percent. This effectively understated Gaz Metro's effective deemed common equity ratio.

  (FBCU Final Submission, pp. 77-82)

AMPC/CEC submit that all of the comparators have common equity ratios that are below the current 40 percent common equity ratio of FEI. They also concede that at 38.5 percent, Gaz Metro is at the top of the range. However, they submit that Gaz Metro is in a far more difficult and risky climate than FEI, given FEI's advantage over electricity is 5 times as great as that of Gaz Metro. AMPC/CEC conclude that a common equity that is the same or greater than Gaz Metro's 38.5 percent would be unreasonable on comparative terms. (AMPC/CEC Final Submission, pp. 33-34)

FBCU submit that neither BCSPO nor AMPC/CEC made any attempt to reconcile the inconsistencies in the comparative analysis among Canadian utilities' capital structures. FBCU further submit that Dr. Booth's submission "that ATCO Gas risk was in the same risk bucket or slightly less risky than FEI" is significant because it suggests that the 40 percent common equity ratio for FEI is justified as ATCO has a 39 percent common equity ratio. (FBCU Reply, pp. 24-25)

Commission Determination

The Commission Panel has previously considered this matter in Section 3.2. The Panel has considered the common equity ratio decisions of other Canadian jurisdictions. **However, because each province is different in terms of its levels of regulatory protection and each utility has its own set of unique circumstances which are only minimally covered in the record of this proceeding, the Commission Panel has determined that only limited weight is to be given to the outcomes of proceedings in other Canadian jurisdictions.** Accordingly, evidence related to the equity ratios of other jurisdictions is used as a reference point only in determining whether FEI's is in an appropriate range.

4.7 Capital Structure – Commission Determination

The Commission Panel has determined that a common equity ratio of 38.5 percent is appropriate for FEI effective January 1, 2013.

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009.

The Commission Panel notes that the 2009 Decision put considerable emphasis on the uncertainty created by climate change legislation that did not exist during the previous cost of capital proceeding. In addition, the 2009 Decision acknowledged the change in the competitive position of

natural gas versus electricity but concluded that there were too many variables at play for this to be considered permanent. The Panel's finding that there is lower long-term risk related to both of these factors since 2009 is indicative of a reduction in overall risk to FEI which needs to be reflected in the common equity ratio.

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

Considering the discussion of optimal capital structure in Section 4.3, the Commission Panel notes that the reduction in common equity ratio to 38.5 percent is reflective of reduced long-term risk and yet balances this against potential disruption caused by a significant weakening of credit metrics.

With respect to credit ratings and metrics, the Commission Panel notes that considerable concern has been raised concerning FEI's credit metrics. In Section 4.4 we found the evidence supportive of maintaining an "A" category credit rating but not at all costs.

The Commission Panel notes that the 38.5 percent equity ratio awarded FBCU in this proceeding falls within the upper end of a range of comparative utilities in other Canadian jurisdictions and considers it to be reasonable on a comparative basis.

FEI is to file within 30 days of this Decision and the accompanying Order G-75-13 a document setting out how and when it will implement the change to its capital structure.

5.0 RETURN ON EQUITY

5.1 Key Issues

The Commission Panel is of the view that an important consideration in this proceeding is the determination of a return that provides investors with the opportunity cost of their investments. The Brattle Report recognizes and elaborates on this fundamental principle:

> "[The cost of capital is] Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk,* it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: . . ." (Exhibit A2-3, pp. 2-3)

However, even if one accepts the concept of the opportunity cost as a foundation of a Return on Equity determination, a remaining challenge is that risk and expected return of the relevant 'alternative investments of equivalent risk' are in the eyes of investors who have access to well functioning capital markets. These expectations are not directly observable to Panel members or to parties in this proceeding who provide evidence for the Panel to consider. Instead, estimates of investors' expectations are based on data that are interpreted through *models* of competitive capital markets. The Panel finds an observation offered in the Brattle Report to be instructive:

> "It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured." (Exhibit A2-3, pp. 3, 5-6)

The evidence presented to the Panel was based on a large variety of specific models that fall into four broad classes: (i) DCF models; (ii) CAPM (iii) ERP models and (iv) CE models. Within these four classes are numerous specific implementations that vary in structure, assumptions, and the data from which they were estimated. For instance, there are multiple DCF models with multiple estimates of the appropriate opportunity cost of an equity investment in the Benchmark Utility FEI. The estimates of the investor's opportunity cost of equity, summarized in Appendix F to this Decision, range from 6.15 percent (Dr. Safir CAPM) to 11.50 percent (Dr. Vander Weide's FRP model.

The models and approaches used by the expert witnesses in this proceeding to estimate the ROE are summarized in Tables included in Appendix F of this Decision.

The key issue then in the determination of the appropriate ROE is assessing how much weight to give to each of these models and their estimates. In turn, the weight given to each estimate depends on a judgment of the validity of the conceptual base of the four broad model classes and a judgment of how reasonable the model inputs are. The Panel has based this judgment, as much as possible, on the objective of determining the opportunity cost of equity.

The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE. As discussed in Sections 5.4 and 5.5, the ERP models (with the exception of Ms. McShane's CAPM based equity risk premium) and comparable earnings model are not based on compelling foundations. Furthermore, model inputs and estimates are largely *ad hoc* and assessments of the validity of these inputs and estimates are based on subjective evaluations with minimal logical guidance. Consequently, both the ERP and CE approaches are given no weight in the Panel's determination of the appropriate ROE for the benchmark utility.

5.2 The Capital Asset Pricing Model

The CAPM is based on consideration of individual investors making portfolio decisions in a well functioning capital market. As such, it is a model of the shareholders who own the shares of the firm. Of all the models used to present evidence to the Panel, we consider that the CAPM provides the underpinnings of investor choice in greatest detail.

The CAPM is based on portfolio theory, a theory that answers the question: If an investor wishes to achieve a particular rate of return and is able to invest in a large set of securities, what investment strategy will deliver the target expected return at lowest possible risk? (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 78) The somewhat surprising answer given by portfolio theory is that all investors will hold a combination of two mutual funds; one made up of all risky securities available, referred to as 'the market portfolio' and the second made up of risk free securities. In contrast to intuition, individual risk aversion will not determine which specific securities to invest in but will

determine how much of an investor's wealth will go in the market portfolio and how much will go into risk-free securities. A more risk-averse individual will hold less of their wealth in the market portfolio and more in treasury bills than a less risk-averse individual.

The result that investors will hold well diversified portfolios instead of individual stocks provides great guidance in elaborating on the seminal Supreme Court of Canada decision of *Northwestern Utilities* that the allowed return on capital is to be comparable to the return that would be earned on "... the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (Exhibit A2-3, p. 2) The CAPM tells us that these 'other securities' are not other comparable firms but are instead comparable portfolios that combine the market and the risk free rate.

The Commission Panel notes that the reason investors are better off holding a mutual fund instead of picking individual stocks is diversification. Diversification builds on another bit of intuition: don't put all your eggs in one basket. As The Brattle Report states:

> "…when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities. Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk." (Exhibit A2-3, pp. 6-7)

Since diversification is a driving force in investor's decisions, leading them to hold broadly diversified portfolios, when they consider the value of an individual stock they do not consider the total risk of the stock in isolation. They instead consider the amount of risk the stock will add to the risk of the mutual fund, recognizing the effect the stock has on the total diversification achieved. The amount of risk that remains after the benefits of diversification is referred to as non-diversifiable or systematic risk. The measure of the systematic risk is called beta. (Exhibit A2-3, pp. 6-7; Exhibit C4-9, p. 9; Exhibit B1-9-6, Appendix F, p. 88)

The CAPM builds on portfolio theory by providing a risk return relationship that recognizes beta as the risk measure. The theoretical foundation and the formulation of the CAPM is discussed in the evidence of Dr. Safir (Exhibit C4-9, pp. 8-11) and in the Brattle Report, which states:

> "The presence of a market underlies the "opportunity cost" interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, "comparable risk," investment B obtainable through the market." (Exhibit A2-3, p. 6)

The opportunity cost of an investment is based on the return on a risk free investment, which is the risk free rate. To this is added a 'risk premium'. In turn there are two parts to the risk premium. The first is the extra return that would be earned by holding the market portfolio on its own instead of the risk free security. The expected return on the market is denoted r_m and the risk premium over the risk free return, r_f, is denoted by (r_m - r_f). This is referred to as the 'the market price of risk' or the 'market risk premium'. The second component of the risk adjustment is beta which adjusts the market risk premium to account for the degree to which the individual stock contributes to the market risk; low beta stocks contribute less than average and earn less than the market rate, high beta stocks earn more.

The advantage of the CAPM is that it distils the complex interactions among risk averse investors trading with each other to a simple equation with three parts:

$$r_e = r_f + (r_m - r_f)\beta$$

where r_e is the opportunity cost of equity.

So, to estimate the investor's opportunity cost requires an estimate of the risk free return, the market risk premium and the beta. In spite of the CAPM's strong theoretical underpinnings, the estimation of these model inputs presents challenges as outlined in the Brattle Report (Exhibit A2-6, pp. 16-25) and in the evidence of Ms. McShane. (Exhibit B1-9-6, Appendix F, pp. 67-70) The challenges include the role to be played by the US data in the analysis.

The Panel recognizes the growing importance of US and indeed global securities in the portfolios of Canadian investors as pointed out in the evidence of Mr. Engen and of Ms. McShane. (Exhibit B1-9-6, Appendix E, pp. 11, 43-50; Appendix F, pp. A-14, A-15) The Panel also recognizes that none of the evidence was based on data related to global portfolios held by investors; for instance, market portfolios were defined as either the Canadian or US market separately and none of the evidence dealt with an integrated global portfolio. Furthermore, currency risk was not considered nor was the magnitude of foreign ownership of FEI. The evidence presented includes CAPM estimates on either US or Canadian data. In light of these concerns with respect to the lack of a complete global

perspective and the potential for risk (including currency risk), the Panel concludes that the more appropriate of these two perspectives is that of the Canadian based CAPM. Therefore, the Panel places greater weight on Canadian based CAPM estimates.

The Panel received a great deal of evidence on various estimates of the following three inputs.

(1) The Risk Free Rate, r_f

Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, all of the experts submit that the appropriate opportunity cost is better measured by the *forecasted* yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted.

Estimates of the risk free return available to investors, based on forecasted long-term Government of Canada Bond Yields, range from a low of 2.95 percent estimated by Dr. Vander Weide (Exhibit B1-9-6, Vander Weide Evidence Appendix G, p. 35) to a high of 4.0 percent by Ms. McShane and Dr. Safir. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 77; Exhibit C4-11, BCUC 1.4.1) Dr. Booth submitted that 3.0 percent was the forecasted yield on long-term Government of Canada Bonds but he considers forecast long Canada bond yields of 3.0 percent to be "well below any 'equilibrium' yield since they are only 1% above the forecast inflation rate and mean locking in a negative real yield for a typical taxable investor." (Exhibit C6-12, p. 60) Dr. Booth testified in cross-examination that:

> "…we do have foreign official flows of money coming into Canada because we are a triple A rate country and they are basically buying Canadian government bonds, pushing up prices, pushing down yields, and pushing them down to a value that I do not think reflects the proper trade-off between risk and return by "an ordinary private investor" making these decisions." (T8:1516)

Accordingly, Dr. Booth adds 0.8 percent to the 3 percent to recognize the alternative, and to arrive at his "Base adjusted LTC forecast" of 3.8 percent. (Exhibit C6-12, pp. 84-85, 93; Exhibit C6-15, BCUC 1.30.3)

In summary, the evidence presented seems consistent in stating that the current rates available on risk free government securities is between 2.6 percent and 3 percent. However, the Panel also agrees with the experts that current monetary policy is historically unusual and subsequently results in the possibility of a higher effective risk free rate. **Therefore, the Panel determines that the estimate of 3.8 percent for the risk free rate is reasonable, corresponds to Dr. Booth's estimate, and is within the relatively narrow range of estimates presented by all experts.**

(2) Market Risk Premium (r_m - r_f)

Estimates of the market risk premium range from 5 percent to 6 percent according to Dr. Booth (Exhibit C6-12, Appendix B, p. 16) to a high of 7.5 percent submitted by Ms. McShane. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 98) The basic estimation methodologies used by all experts were similar in that they were based on historical data on market returns and returns on risk free securities. They differ in some important details.

Ms. McShane bases her estimate on the average return on an investment in the market and shows, in Table 10, page 80 of her evidence that the average return on equities in Canada over the 1924-2011 period is 11.4 percent. From this number, Ms. McShane subtracts the *current* forecasted long-term Government of Canada Bond yield of 4 percent to arrive at her 7.5 percent estimate of the risk premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 87) The Commission Panel understands that it is typical to base the risk premium on the average historical difference between the return on the market and the risk free rate. It is our understanding that this approach is to deal with, among other things, the fact that historical market returns and historical bond yields reflect historical inflation while current returns reflect current inflationary expectations. This is an especially important consideration in the current environment where inflationary expectations are at a historically low level. (T3:483-485; T5:713-715)

To illustrate our concern with the approach used by Ms. McShane, the Commission Panel notes that there are times in the last 30 years where this approach would have yielded a very small or even negative risk premium. For instance, Schedule 2 of Ms. McShane's evidence reports that the yield on Long-term Canadian Government bonds in 1990 was 10.69 percent. If this was subtracted from the average market return it would have yielded an unreasonably low market premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, Schedule 2, p. 1; T8:716-717)

Ms. McShane was asked if she could provide a single reference to a textbook or Journal article that advocated using her approach. Her response was that she 'probably could not' (T5:717-718). Accordingly, the Panel gives no weight to the risk premium estimate of 7.5 percent provided by Ms. McShane.

Dr. Booth provides evidence that the historical risk premium is between 5 percent and 6 percent. He adjusts this range for 'Operation Twist' to obtain a risk premium estimate of 5.8 percent to 6.8 percent with a midpoint of 6.3 percent. (Exhibit C6-12, p. 93) Operation Twist refers to monetary policy intended to influence returns at various maturities including long maturities.

Dr. Booth provides two tests of the robustness of his estimate. One robustness test is to compare his estimate of the market risk premium with expectations used by FEI in assessing its defined benefit pension liability. Dr. Booth takes the expectation of market return of 7 percent, provided by FEI's consultants, and converts this geometric return to an arithmetic return. From this, Dr. Booth infers that FEI has, for purposes of valuing its pension liability, accepted an expected market return of 9 percent. Based on this he concludes, on page 93 of his evidence, that "[a]s a result, FEI's data seems consistent with a market risk premium of about 6.2%." In their Final Submission, FBCU submit that the Panel should not rely on data used in assessing pension liabilities. FBCU assert that, since actuaries provided the data, they naturally reflect a conservative bias. FBCU cited its witness Ms. McShane, who stated that pension fund managers and actuaries "... have absolutely no incentive to be anything but very conservative because they have a lot on the line. A pension fund needs to be able to assure that it has funds available to pay its retirees." (FBCU Final Submission, p. 151)

The Panel does not accept the assertion that the actuarial expectations are conservatively biased and should be rejected. Actuaries are charged with fairly assessing pension plan liabilities. The Panel finds, therefore, that this robustness test is indeed helpful in assessing the risk premium.

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent

market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent.

FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion. Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.

Other estimates of the risk premium were also in the range of 5.96 percent (Dr. Safir's Canadian estimate, Exhibit C4-9, p. 12, Table 1) to 6.6 percent. (Dr. Vander Weide's estimate, Exhibit B1-9-6, Appendix G, p. 38) **Given the preceding discussion, the Commission Panel accepts a market risk premium of 6.4 percent as it is within reasonable forecasts presented.**

(3) Betas

Evidence on the beta estimates is largely based on a standard approach of regressing returns from comparable firms on market returns. Since FEI does not have traded equity, estimates of beta must be based on comparable firms. In the evidence submitted, the set of comparable firms include Canadian firms as well as, in some cases, US-based firms.

Dr. Vander Weide submits a beta estimate of 0.92 based on the historical ratio of the average utility risk premium to the S&P risk premium. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 42) Aside from the fact that this is a beta estimate for US Utilities (T6:1092), the method differs significantly from the more commonly accepted method(s) of calculating a beta estimate as set out in the Brattle Report (Exhibit A2-3, pp. 15-16), and as calculated by the other witnesses in the proceeding. Accordingly, the Panel places no weight on this beta estimate.

The other beta estimates submitted range from a low of .36 by Dr. Safir for his Canadian CAPM estimate (Exhibit C4-9, pp. 12, 15), to a high of 0.65-0.70 by Ms. McShane. (Exhibit B1-9-6, pp. 97-98) Dr. Booth provides an intermediate estimate of 0.45-0.55. (Exhibit C6-12, Appendix C, p. 14) All

estimates begin with a regression of returns of the comparator firm on market returns with the 'raw beta' being the slope coefficient of the regression.

The differences among estimates largely result from adjustments that are made to the raw betas. Empirical evidence indicates that the regression based beta estimates seem to understate the betas of low risk firms and overstate the betas of high risk firms. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 96; Appendix A to Ms. McShane's Evidence, pp. A-21-26; Exhibit B1-9-6, Appendix G, p. 41) Since, by construction, the beta of the market is one, the adjustments are intended to bring the estimated beta's closer to one. To accomplish this, Ms. McShane contends that it is appropriate to adjust utility betas towards the market average of 1.0. (Exhibit B-19-6, McShane Evidence, Appendix F, p. 96) Both Dr. Booth and Dr. Safir, on the other hand, contend that the adjustment should be to the utility average beta that is in the range of 0.5 - 0.6. (Exhibit C6-12, Booth Evidence, p. 71; Exhibit C4-9, Safir Evidence, p. 15)

None of the evidence presented revealed the actual bias in beta estimates; instead the experts assert a particular adjustment. In cross-examination Ms. McShane acknowledges that utility betas may indeed not trend towards one.

Mr. HOBBS: And because regulation protects companies, isn't it also true that you would not expect betas for utilities to ever trend towards 1?

Ms. McSHANE: To trend towards 1. I guess I don't disagree with that. I never said that they would. (T4:549)

Similarly, in cross-examination at T6:1073, Dr. Vander Weide says*:*

DR. VANDER WEIDE: Yes. And I readily recognize that betas for utilities don't adjust toward 1.0.

In their Reply, FBCU argued:

> "Ms. McShane's relative risk adjustment of 0.65-0.70 for a benchmark utility, based partly on adjusted betas, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 55% of the risk premiums achieved on the equity market portfolio. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower)

> returns than the CAPM and beta would have predicted. It is not logical to conclude that, based on that experience, utility investors now only expect to achieve an equity risk premium that is 45% to 55% of the equity market risk premium (or Dr. Safir's lower 36%) simply because utility share price movements have not exhibited a high degree of correlation with price movements in the overall equity market." (FBCU Reply, p. 35)

An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.

5.2.1 Adjustments to the CAPM

A number of experts raised concerns about the validity of the simple 'single factor' CAPM. The term single factor refers to the reliance of the prediction of the model on only the market portfolio, the factor implied by the theory. Ms. Ahern introduced in evidence a summary article that shows how other factors such as firm market capitalization (size) and market-to-book ratios can provide added explanatory power to the single factor CAPM. (Exhibit B2-7, Evidence of Ms. Ahern, pp. 13-14; Exhibit B2-7, Attachment PMA-1, Exhibit PMA-9)

The CAPM is by far the most widely studied asset-pricing model and it is not surprising that more is known about its empirical performance than other asset pricing models. This evidence also implies that improved performance can be achieved by including these well-studied extensions of the model. The Panel notes, however, that none of the experts relied on the extensions as found in the literature findings in dealing with the shortcomings of the single factor CAPM. (Ms. McShane, T5:720-722); Dr. Vander Weide, T6:1102-1108; Dr. Safir, T7:1259-1262; Ms. Ahern, T7:1355-1357; Dr. Booth, T8:1658-1663) Instead, the evidence presented by different experts responded to the relatively poor empirical performance of the CAPM in a number of *ad hoc* ways.

Dr. Vander Weide's response to the weak empirical performance of the CAPM is to place no weight on CAPM estimates even though he provides estimates himself. In cross-examination, however, Dr. Vander Weide testified that he did not attempt any standard adjustments to the CAPM that might improve performance. For instance, he did not adjust for the importance of international markets to Canadians, he did not adjust for changes in capital structure and he did not study the ability of a

multi factor model to capture returns. (T6:1108-1111) As a result, the Panel does not accept Dr. Vander Weide's response to the relatively poor performance of the CAPM and continues to place weight on the model.

Ms. McShane and Dr. Booth both attempt to improve the performance of the CAPM by adding empirical analysis in order to augment the basic model. Dr. Booth is clearest in his objective when he states: "I regard this sort of adjustment as converting the CAPM into a conditional CAPM where the CAPM holds conditional upon the state of the financial markets." (Exhibit C6-12, p. 81)
Dr. Booth testified that an academic literature exists that supports the analysis of a conditional risk premium and his credit spread adjustment is consistent with that literature. (T8:1659)
Ms. McShane does not provide the same link to the academic literature and acknowledged, in cross-examination, that her work is along the lines of a multi factor CAPM. (T5:718-720)

The Commission Panel appreciates the efforts of the experts to recognize and deal with the shortcoming of the single factor CAPM. The evidence suggests there are two main thrusts to this effort: i) improving the estimate of the risk premium by conditioning on the current state of the capital markets; and ii) improving estimates of the risk return relationship by adding the factors to the single factor CAPM. Notwithstanding the efforts, the Commission Panel finds that we are not able to assess the validity of the extensions to the single factor CAPM that were presented as there is insufficient evidence involving the use of multi-factor models in this proceeding. The experts expressed reluctance to include other potential extensions to the CAPM that they thought were too complex. This is further addressed in Section 8.

In this regard, the Panel agrees more generally with the specific concern of ICG who argues that in Ms. McShane's CAPM based ERP, she "…makes an adjustment to the market risk premium of approximately 100-150 basis points because in her opinion market risk premium are in fact correlated with the risk free rate." ICG cites Dr. Safir as characterizing the adjustment as arbitrary and not in keeping with the CAPM model. ICG submits that before the Commission Panel accepts this adjustment there must be very strong evidence to support it. In the absence of such strong evidence, the CAPM specifications should not be changed. ICG goes on to say that: "The evidence regarding the correlation (inverse relationship) between the market risk premium and the risk free rate is in fact just that, it is a subjective judgement, with at best, very limited evidence in support of Ms. McShane's proposed departure from the CAPM model." (ICG Final Submission, p. 19)

In support of its argument that there is limited evidence in support of Ms. McShane's adjustment ICG submits that her evidence in support of a relationship between the market risk premium and the risk free rate is presented on a cumulative basis. It argues that when the same data is provided on a non-cumulative basis the US risk premiums do not follow income returns in the manner she suggests (Exhibit B1-53, Undertaking No. 14) and in some instances the data support the opposite conclusion to that observed by Ms. McShane.

Rather than relate the models presented in this hearing to the academic literature, as presented by Ms. Ahern for instance, the extensions seem to be somewhat *ad hoc* leading to the sort of concerns raised by ICG. There is no evidence, therefore that the models present were not the result of a "fishing expedition." That is, the Panel does not know if other adjustments or specifications would produce different results and we cannot assess whether other non-reported specifications should logically be ignored. In the absence of persuasive evidence that these are of value, the Panel is content to consider simple single factor models. At this time the Panel is not persuaded that the specific model extensions that are presented are valid and hence places no weight on them. However, the Panel recommends that in the future improvements in the model can also be brought into evidence, but the evidence should then include both the model extensions as well as a basis on which to judge the validity of the extensions.

5.2.2 CAPM Based Estimate of ROE

Summarizing the discussion above, the Commission Panel has applied the required judgment and accepts the CAPM estimate at 7.64 percent. This reflects a risk free rate of 3.8 percent, a risk premium of 6.4 percent, and a beta of 0.6.

5.3 Discounted Cash Flow Approach

The basis of the DCF approach is the principle that in a competitive market investors who purchase securities are essentially bidding for expected future cash flows that the security entitles them to. Competition implies that investors search for 'good deals', ones that offer the lowest price for a particular cash flow of a particular risk. The higher the price paid, the lower the expected return, so, in an attempt to improve their lot, investors search for securities that trade at a low price generating a high expected return. In their quest for high returns, they are willing to pay a price up to a level

that would make the purchase at least as good as the next best alternative, i.e. equal to their opportunity cost. Of course, in a competitive market, other investors are also looking for good deals and, as a result, competition ensures that observed prices generate returns equal to the opportunity cost.

The theory implies that if one can observe prices and expected cash flows one can infer the investor's opportunity cost. The DCF model applies this logic to equity investment in order to infer the opportunity cost of equity. It is assumed that cash flows to investors consist of dividends and that stock prices reflect investors' expected dividends and the opportunity cost of the investment. If we observe prices of equity and estimate all future dividends that the equity gives title to, then one can infer the opportunity cost of equity. (Exhibit A2-3, pp. 26-29; Exhibit B1-9-6, McShane Evidence, Appendix F, Appendix C, p. C-1)

An attractive feature of the DCF model is that it assumes, unlike the CAPM, that investors hold realistic investment horizons; both short and long-term investors estimate all dividends that the firm will provide over its lifetime. As with the CAPM, a significant disadvantage to the Commission is that for FEI none of the inputs, for example, price, dividends, or opportunity cost, are directly observable. The equity of the benchmark utility is held by Fortis Inc. and not actively traded. Therefore, future dividends are in the eye of the beholder as is the opportunity cost of capital. As a result, the opportunity cost estimate rests entirely on inferences that are commonly based on comparable firms. Not only should these firms be comparable, they should also have actively traded equity, and a source for estimating expected dividends.

Simplifying assumptions make the task of estimating dividends easier and the evidence submitted was all based on one of two simplifications or models. The 'Perpetual Constant Growth' model assumes that investors estimate the next dividend to be paid by the company and a single rate at which dividends will grow in perpetuity. The validity of the constant growth model is reduced when the estimated growth rate comes close to the opportunity cost (as this implies an extremely large stock price) and the model is invalid if the expected growth rate is greater than or equal to the opportunity cost of equity. The second model, 'the multi-stage growth' model, also requires an estimate of the next dividend to be paid but then allows investors to see multiple stages of constant growth; for example, the investor might expect growth of 4 percent for the next five years, 3 percent for the 5 years after that, followed by a constant perpetual growth rate of 2 percent starting

11 years hence. Although the long-term perpetual growth stage must meet the same growth restrictions as the constant growth model, the earlier stages are not restricted in this way. Therefore, multi stage growth models allow considerable more flexibility in dealing with growth forecasts. The Commission Panel has considered DCF-based ROE estimates presented by Ms. McShane, Dr. Vander Weide, and Dr. Safir.[6] Dr. Booth's DCF estimate for the market as a whole was used as a check on his CAPM estimate and is discussed with that estimate previously in Section 5.2.

1) Ms. McShane's estimates

Ms. McShane provides five different estimates with ROE estimates based on the DCF model. The estimates range from 8.6 percent to 11 percent. The estimates were variously based on 12 US Utilities or 5 Canadian utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 113) FBCU submit that: "The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%)." (FBCU Final Submission, pp. 105-107) The FBCU also point out that Ms. McShane relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations, minimizing the need to superimpose on the analysis her own subjective view of growth expectations. (FBCU Final Submission, p. 106) Ms. McShane recognizes, however, that the forecast period for analysts' long-range earnings and dividend forecasts is typically three to five years over a business cycle (Exhibit B1-9-6, Appendix F, Appendix C, p. C-4), and that extending these forecasts into perpetuity in the constant growth model can overstate expected return. (T4:664-665)

2) Dr. Vander Weide's estimates

Dr. Vander Weide only presents evidence based on a constant growth DCF and only for a sample of US Firms. He relies on I/B/E/S Thomson Reuters Mean Growth forecasts to estimate dividend growth. Dr. Vander Weide's application of the DCF model to his comprehensive group of utilities produced a result of 10.3 percent, and to his smaller group of utilities, 10.0 percent, including 0.50 percent for flotation costs. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, pp. 27-31; Exhibits

[6] Dr. Booth employed a Constant Growth model but only to estimate the market wide expected return. This was used as a check on his CAPM estimate and so is not included in this discussion.

6 and 7 of his evidence) The FBCU submit that "…Dr. Vander Weide's DCF estimates are reasonable and should be given significant weight." (FBCU Final Submission, p. 108)

3) Dr. Safir's estimates

Dr. Safir uses a two stage DCF model to develop two estimates; one of 8.99 percent based on 5 Canadian firms and one of 8.86 percent based on a sample of 18 US utilities, before adding flotation costs amounting to 5 percent of the initial ROE estimates. (Exhibit C4-9, pp. 24-26, and Schedules 3 and 4)

Commission Panel Discussion

The Brattle Report observes: "The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality." Elsewhere the report is more specific: "The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years." (Exhibit A2-3, p. 30)

The FBCU urges the Panel to give the DCF considerable weight, while the AMPC/CEC submits that "a DCF analysis can provide a helpful "check" on CAPM estimates, but the Commission should be cautious not to rely too heavily on it." (FBCU Final Submission, p. 89; AMPC/CEC Final Submission, p. 41)

The Commission Panel is of the view that, notwithstanding the concerns expressed about the approach, considerable weight should be given to the DCF but also accepts that caution should be used in assessing the growth estimates presented. A number of specific concerns arise with respect to the evidence presented:

a) **Reliance on analysts' short-term forecasts as the long run forecasts in constant growth formulas**:

This reliance appears in the single stage models presented by Ms. McShane and Dr. Vander Weide. For instance, Ms. McShane's estimate based on Canadian comparable firms assumes perpetual dividend growth of 7.5 percent. Since this is larger than her estimate for long run GDP growth of 4.3 percent, Ms. McShane seems to imply that FEI will grow to be an increasingly larger segment of the economy. This is inconsistent with the evidence presented in Appendix F of her testimony where she enumerates many reasons why consumers, both residential and commercial, will migrate from natural gas to other sources. Similarly, Dr. Vander Weide's estimates of the cost of capital use short-term analysts' forecasts to estimate the constant growth model. Similar to Ms. McShane, the resulting implication is that FEI will become a larger component of the economy over time, a conclusion that seems inconsistent with FEI's submissions regarding a shrinking market share and falling customer capture rates. (FBCU Final Submission, p. 53) We also note that Dr. Vander Weide included firms whose growth rate exceeded his estimate of the cost of equity in his comparable firms. As noted above, such a growth rate is inconsistent with the DCF constant growth model yet were included in his sample without adjustment. This calls into question the DCF estimates presented by Dr. Vander Weide.

The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.

b) **Reliance on comparable firms operating in the US**:

The AMPC/CEC submits that the use of US based comparable firms renders DCF estimates of limited value. In their submission, AMPC/CEC cites Dr. Booth as follows:

> "[In the past] we had lots of pure play utilities in Canada, where you could do a DCF. In particular, all the local telephone companies were still regulated by the CRTC on a rate of return rate based method, and we had Island Telephone traded, Maritime Tel traded, NewTel traded, Bruncor Traded, Bell Canada traded, B.C. Tel traded. So we had a lot of traded rate of return regulated utilities that we could actually do DCF tests on. Unfortunately, they don't exist anymore." (T8:1493-1494)

While the Commission Panel concurs with the concern about comparability of US based firms, it also agrees with the argument of FBCU that, given the paucity of comparable Canadian firms, also recognized by Dr. Booth, augmenting Canadian data with US firms is appropriate. (FBCU Final Submission, p. 94) The Panel also recognizes the need for careful informed judgment in adjusting the US based estimates to reflect differences in the respective environments.

c) **Analysts' forecast bias**:

Given the heavy reliance on the forecasts of equity analysts, the AMPC/CEC submit that analyst bias may inflate DCF ROE estimates. (AMPC/CEC Final Submission, p. 59) FBCU argues that analysts' forecasts for utilities are not biased. (FBCU Final Submission, p. 111) The Brattle Report notes that studies have shown that analysts' forecasts are likely to be more accurate in utilities than in other sectors and bias is likely to be less in utilities than other sectors. (Exhibit A2-3, pp. 28-29)

The Panel finds that there is reason to be cautious of potential analyst bias in the utility sector. The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made. The Panel expects that future hearings will be informed of the latest research on bias in the analyst's reports on the utility sector.

Overall Assessment

The Commission Panel finds that the constant growth DCF models presented have growth assumptions that render the estimates questionable given the discussion above. Therefore, we place little weight on the submitted estimates that are based on the constant growth DCF. The estimates that the Panel found most helpful are Ms. McShane's multi-stage estimates in the range of 8.6 percent to 9.2 percent and Dr. Safir's estimates of 8.86 percent to 8.99 percent (two-stage). (Appendix F) Applying the appropriate judgment required, **the Commission Panel accepts an 8.9 percent DCF based estimate of the opportunity cost of equity.**

5.4 Equity Risk Premium Models

5.4.1 Introduction

FBCU's witnesses Ms. McShane and Dr. Vander Weide each provided results from various models, classified as equity risk premium models. Ms. McShane provided the results of three different 'types' of ERP models, comprising numerous estimates. Dr. Vander Weide used two types of ERP models, which he termed "Ex-Ante" and "Ex-Post" risk premium tests, and used two different samples for each of the two types of tests. None of the other witnesses relied on the ERP.

The Brattle Report summarizes the form and some of the issues concerning ERP models. According to the report, the ERP is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. It notes that the historical risk premium is commonly estimated as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the sample period over which the estimate of the spread (i.e., the risk premium) is to be based. The Brattle Report states that it is important that the analysis is consistent in its choice of a debt instrument to determine the cost of debt and that used to determine the risk premium. It also notes that the realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. (Exhibit A2-3, p. 31)

The Brattle Report states that the forward-looking model requires that the analyst determine a proper measure of the cost of debt and how to estimate the expected risk premium. It says that because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural candidates for the expected bond cost. However, determining the expected equity return is more difficult and requires the reliance on an estimation technique. It notes that it is common to rely on DCF models to determine the risk premium in the forward-looking version of the model. (Exhibit A2-3, pp. 31-32)

5.4.2 Discussion of the ERP Method and Results

The Brattle Report states that the risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model, but that "…the Risk Premium Model

does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP." (Exhibit A2-3, p. 33) Moreover, there is a concern that the historical risk premium approach to the ERP assumes that a historically realized risk premium is an appropriate measure for expected returns, but that over any given period, especially short periods, realized returns can differ substantially from expected returns. (Exhibit A2-3, p. 31)

A strength of the model identified in the Brattle Report is that the information on which the model relies is auditable. However, it notes that because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. It further states that the implementation of the model largely determines its ability to capture the systematic risk of companies, noting that, unless a forecasted return for relevant companies is used, the model will be unable to estimate reliably the cost of capital across different economic conditions. (Exhibit A2-3, pp. 34)

Commission Determination

The purpose of a rate of return model is to provide structure to the discussion of 'what a fair rate of return is.' Models used to assess this question provide structure and clarity and, in turn, a basis for the data to consider the appropriate interpretation to give it and the estimates.

The lack of a strong theoretical footing for ERP, as noted in the Brattle Report, may explain the large number of ERP estimates submitted to the Panel and the potentially intractable discussion of the merits of the models. There is simply little to help focus the analysis and as a result many models can be submitted as 'true' even though there is little on which to judge the validity of the submission.

The large number of estimates along with the absence of a compelling framework raises the following reservations about the estimates and indeed about the entire approach:

1. The models combine elements of the CAPM and the DCF with other ad hoc adjustments. Since evidence was presented on both the CAPM and DCF, it is not clear what is added by looking at these alternatives.

2. While it is not clear what is gained through these ERP models, it is clear that clarity is lost. In particular, the assumptions used in various estimates are difficult to evaluate. Ms. McShane, for instance, uses return estimates based on a sample of US firms with the 30-year Canada Bond rate in some estimates of the risk premium but in others uses 30-year A-rated utility/government bond yield spreads. (Exhibit B1-9-6, Appendix F, p. 99) Similar ad hoc assumptions are also found in Dr. Vander Weide's analysis. For instance, AMPC/CEC point to Exhibit C6-21 to demonstrate that if bond returns rather than bond yields were used in the analysis, the average Ex-Post risk premium for utilities would be approximately 4.47 percent or 2.3 percent less than Dr. Vander Wiede's estimate. Consequently, the AMPC/CEC argues that the Ex-Post estimates of Dr. Vander Weide must be ignored or if not ignored, then reduced by 2.3 percent. However, FBCU state that it is appropriate to use bond yields as the true risk-free rate. It is not clear, however, why the risk free rate is not estimated using a risk free return.

   Again, while judgment is always needed to evaluate estimates, without a theoretical base, there is no consistent way in which these differences of opinion can be assessed.

3. Since the model variations are ad-hoc they are subject to the concern that they may be subject to a "fishing' expedition" criticism. In contrast, while we can obtain various results from the CAPM or DCF models by changing parameters such as the risk premium in the CAPM or the growth rate in the DCF, the reasonableness of the selected parameter can be questioned.

Given these concerns along with the fact that there is ample evidence on both CAPM and DCF based estimates, the Panel places no weight on the ERP estimates submitted.

5.5 Comparable Earnings Approach

The Brattle Report states notes that the CE method is one of the traditional approaches to the cost of capital estimation, but that it does not have a financial economics foundation or strong theoretical basis. The report states that the legal decision, *Federal Power Commission et al v. Hope Natural Gas Co.,*[7] which stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks, is often cited in the use of comparable earnings, but that neither the Canadian nor the US Supreme Courts has identified any specific methodology to determine a "fair return." (Exhibit A2-3, pp. 11, 36) The Commission Panel observes that much has been learned about financial economics since 1944. In particular, the notion of a comparable investment has been carefully cast in terms of investments in portfolios of

[7] 320 U.S. 591 (1944); 64 S. Ct. 281; 88 L.Ed. 333 (1944) U.S. Lexis 1204

comparable risk since portfolios are more efficient in achieving any expected return than is a single security.

The CE method requires the use of a sample of unregulated companies as comparators, since the use of regulated companies to estimate the comparable cost of capital would be circular. The Brattle Report notes that because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company, and because the estimates from the model do not come from regulated companies or activities, the method does not recognize the regulatory context in which the cost of capital is being applied. (Exhibit A2-3, pp. 35, 38)

The Brattle Report states that a major issue with the comparable earnings method is whether realized book returns are a good proxy for the return that investors expect going forward and notes that it is a backward looking measure with no consideration of current market conditions. (Exhibit A2-3, pp. 36-37)

Ms. McShane submits that the fair return standard "…is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard…." (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8) [emphasis in the original] In her view, the comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard and it is critical that the regulator recognize the comparable returns standard when setting a fair return. (Exhibit B1-9-6, Mc Shane Evidence, Appendix F, p. 114)

Ms. McShane submits that the comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Ms. McShane arrived at her comparable earnings estimates based on the earnings on book-value of 21 unregulated Canadian companies from 2004-2011. (Exhibit B1-9-6, Appendix F, pp. 113-116) She arrives at the following result: "To recognize the unregulated companies' higher risk, a

downward adjustment of 125 to 150 bps to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%." (Exhibit B1-9-6, Appendix F, p. 116)

To complete her comparable earnings estimate, she assesses the need for a market/book adjustment to the comparable earnings results. She submits that "[t]he similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios." (Exhibit B1-9-6, pp. 116-17)

Dr. Booth submits that the average ROE increases when one starts adding low-risk firms to a comparable earnings sample and then progressively decreases as more risky firms are added, particularly after the lowest risk firms are added. He argues that: "…to get a high ROE from a sample of comparable earnings firms simply means coming up with "reasonable" screens to narrow down the sample and exclude those firms with significant losses. (Exhibit C6-12, p. 6)

He used book-value based estimates for Corporate Canada as a whole, using Statistics Canada reported earnings for the period 1987 to 2011 and the TSX composite for the same time period. He arrived at a CE estimate for the Canadian market of 9.3 percent, and says that "Like the overall stock market return this then needs to be lowered for the lower risk attached to regulated utilities." (Exhibit C6-12, Appendix E, pp. 3, 7, Schedule 2)

Dr. Booth submits that CE "…is totally unreliable unless a market to book adjustment is made which is rarely the case." (Exhibit C6-15, BCUC 1.39.0) He also submits that a "…market to book adjustment is needed since low risk firms usually have market power which is reflected in higher ROEs. It is incorrect to then allocate to a utility an ROE from a sample of firms that reflects market power when regulation is designed to remove this market power." (Exhibit C6-15, BCUC 1.67.1)

Dr. Booth also says that a problem with looking at past ROEs is that they are earned on historic accounting book equity that does not reflect what can be earned on investments today. (Exhibit C6-12, Appendix E, p. 5)

The AMPC/CEC argues that the Commission should place little or no weight on the comparable earnings test. (AMPC/CEC Final Submission, pp. 38, 60)

Dr. Safir used two market-value based estimates: one for the same Canadian sample of 21 companies used by Ms. McShane; the other based on a sample of 31 US companies in the consumer goods, industrial goods or service sectors using the same sample selection criteria as Ms. McShane used for her Canadian sample. (Exhibit C4-9, pp. 28-29)

Dr. Safir calculated his comparable earnings estimates "…using net income and market value of equity…." He submits that because his comparable earnings estimates were calculated using market-based values instead of book value, they more accurately capture the conditions in the current capital markets in which the benchmark firm would be competing for capital. He goes on to say that his method accounts for factors such as inflation, since both the net income and the stock prices will reflect the level of inflation occurring at the time these numbers were reported and that "[b]ook value-based calculations of comparable earnings will not account for inflation." (Exhibit C4-9, p. 30) Using his market-value based method of calculating CE Dr. Safir arrived at estimates of 6.85 percent for his Canadian sample and 5.81 percent for his US sample. He submits that the Canadian estimate should be given twice the weight of his US estimate and arrives at a weighted average estimate of 6.50 percent. (Exhibit C4-9, p. 33)

Dr. Vander Weide did not provide a CE estimate.

Commission Determination

The fundamental issue regarding the CE test is its lack of a basis in financial economics. The approach requires a sample of unregulated companies of similar risk, but creating a sample of unregulated companies that are, and can be shown to be, of similar risk is difficult without a theoretical basis such as the CAPM or the DCF. Dr. Booth has pointed out the issues that arise when even 'reasonable' screens are used to eliminate companies from the entire universe of companies to create a sample. Moreover, the CE method is retrospective, whereas the ROE to be established for the benchmark utility is prospective.

In her evidence, Ms. McShane submits that: "The economic principle guiding the fair return is the opportunity cost principle." She also submits that one of the requirements of the FRS is that the return allowed is comparable to the returns of enterprises of similar risk and that it is critical that the regulator recognize the comparable returns standard when setting a fair return. She also states that the CE test is an implementation of the comparable returns standard and is to be distinguished from the cost of attracting capital standard. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 2, 8, 114)

During cross-examination a discussion on whether the comparable earnings test reflects an investor's opportunity cost concluded with the exchange below:

COMMISSIONER GIAMMARINO: But you would agree that in terms of an opportunity cost, it doesn't match up that closely to what we would consider the exact opportunity cost to the investor.

Ms. McSHANE: A: No, it is not an opportunity cost in the same sense that you were talking about. (T5:732-35)

The Commission Panel addressed the FRS in Section 2 and recognized that a fair or reasonable overall return on capital should be comparable to the return available from the application of the invested capital to other investments of like risk (comparable investment requirement). However, the Commission does not accept that this requirement means that it must use the comparable earnings method as a means of determining what return is required to meet the FRS. Modern finance theory has clearly established that comparable risk is assessed relative to a *portfolio* rather than a single stock. This is indeed the basis of the CAPM and other extensions of risk return modules. Searching for individual firms of comparable risk is consistent with this only if the comparison recognizes non-diversifiable risk as the relevant characteristic. This is exactly what is done when CAPM comparators are sought. But this is ignored when companies are considered comparable on dimensions other than systematic risk.

The preceding discussion highlights some of the serious problems the comparable earnings method contains as a means of determining the return required to meet the FRS. **Consequently, the Commission Panel places no weight on the comparable earnings results.**

5.6 Allowance for Financing Flexibility

Ms. McShane described financing flexibility allowance as intended to cover three distinct aspects: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle (Exhibit B1-9-6, McShane Evidence, Appendix F, p. F-1). Flotation costs and financing flexibility adjustments are typically applied to the market-based cost of equity estimates, i.e., the CAPM and the DCF models.

Ms. McShane provided an allowance of 50 basis points for each of her market based tests in order to maintain the market value at a small premium to the book value. In the alternative, should the Commission rely only on the market-based tests, Ms. McShane proposed an allowance for financing flexibility at 1.0 percent. (Exhibit B1-20, BCUC 75.2.1)

Dr. Vander Weide provided an allowance of 50 basis points for flotation and financing flexibility. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 35)

Dr. Booth provided an allowance of 50 basis points, stating that the market opportunity cost should be adjusted upwards to include issuing costs or a financial flexibility adjustment to make sure that shares can always be sold to net out the original cost included in the rate base, which is all that earns the fair ROE. He also noted that most regulators in Canada have allowed 50 basis points for these new issue costs (Exhibit C6-12, p. 8).

Dr. Safir referred to a survey of flotation costs, which determined them to be approximately 4.5 percent of the recommended rate of return. Based on the 4.5 percent, Dr. Safir applied 5 percent of the rate of return, an equivalent of around 32 to 40 basis points for his CAPM models and 47 bps for his DCF model, to reflect the marginally higher costs that would be faced by Canadian issuers either crossing the border to utilize the US market or in issuing in the smaller Canadian capital market. (Exhibit C4-9, pp. 16-18)

Commission Determination

The Commission Panel accepts the allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE. As indicated in Section 5.5, the two market-based tests, CAPM and DCF are given equal weight in the determination of the allowed ROE for the benchmark utility.

With reference to Ms. McShane's proposed additional 50 bps if the CE test is not accepted, the Commission Panel is of the view that each test to estimate the fair return is applied separately to provide a different perspective and each test's results are not contingent upon the results of other tests. Therefore, the Commission Panel does not accept the conditional 50 bps in Ms McShane's alternative proposal.

5.7 Fair Return on Equity – Commission Determination

The Panel finds that the DCF and CAPM should be given equal weight in determining the ROE. Moreover, the Panel finds that CE and other ERP models have insufficient merit to be accorded any weight in the determination of the fair ROE. Considering the CAPM based estimate of 7.64 percent and the DCF estimate of 8.9 percent, the Panel concludes that the ROE, before adjustment for financing flexibility, of 8.25 percent is an appropriate base as it falls in the midpoint range of the two estimates. When an allowance for financial flexibility of 0.5 percent is added, the resulting ROE is 8.75 percent, to be effective January 1, 2013, provided for by Order G-47-12 and confirmed in Order G-187-12. **The ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula discussed and adopted in Section 6.**

FEI is to file within 30 days of this Decision and accompanying Order G-75-13 amended rate schedules in accordance with paragraphs 1 and 2 of Order G-75-13 as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013. FEI shall inform all affected customers of the final rates by way of customers notice.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

6.1 Introduction

In 1994, the Commission determined that the Benchmark ROE was to be estimated annually by an Automatic Adjustment Mechanism (AAM).[8] This AAM was eliminated by Order G-158-09 issued concurrently with the 2009 Decision. In eliminating the AAM the Commission stated that: "... in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard." (2009 ROE Decision, p. 72)

One of the stated purposes of this proceeding was to review the possible return to an AAM for setting an ROE of the benchmark utility and examine potential AAM models. In this Section, the Commission determines that:

- Reinstituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings is appropriate.
- A two-variable model AAM is to be instituted to set the benchmark ROE on an annual basis commencing in the 2014 calendar year for a period of two years.
- Implementation of the model will be subject to the actual long Canada bond yield meeting or exceeding 3.8 percent.
- The new formula will initially utilize the ROE of 8.75 percent as determined in Section 5.7.

6.2 Should the Commission Re-institute an AAM?

In considering re-instituting an AAM, the Commission Panel reviewed proposed AAMs to determine whether they would meet the Fair Return Standard or whether, as FBCU submit: "The Fair Return Standard is best met in intervening years until the next comprehensive cost of capital reviews by holding the ROE constant." (FBCU Final Submission, p. 153) In addition, the Panel examined the status of AAMs in other Canadian regulatory jurisdictions.

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[8] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., -- Decision and Order G-35-94, June 10, 1994.

6.2.1 Status of AAMs in Other Canadian Jurisdictions

The Brattle Report surveyed the cost of capital practices in Canada including the formulas used to set the ROEs in Ontario and Quebec. (Exhibit A2-3, pp. 64, 72)

In the 2009 Decision, FBCU was directed to complete a study of AAM alternative formulas and report to the Commission. In compliance, FBCU filed the 2010 report, "A Review of Automatic Adjustment Mechanisms for Cost of Capital" prepared by Concentric Economic Advisers (Concentric). The 2010 Report provided an examination of the use of AAM formulas in other jurisdictions, contrasted these with alternatives and considered the merits of various approaches. While not recommending that a formula be adopted, Concentric identified attributes that should be considered if an AAM is adopted in the future. (Exhibit B1-9-6, Appendix I) In this proceeding, FBCU again engaged Concentric to provide an update of its analysis, which examined the use of ROE formulas in other jurisdictions. The update included the following observations with regard to Canadian jurisdictions:

- The Ontario Energy Board (OEB) continues to rely on its AAM which it modified in 2009. The modified formula is based on 50 percent of the change in forecast long-term Canada bond yields and 50 percent of the change in observed A-rated utility bond index over the 30-year Canada Bond yield.
- In Quebec the Régie de l'énergie (Régie) modified its previous formula in 2012 to incorporate 50 percent of the change in utility bond spreads in addition to the existing formula's 75 percent of change in government bond yields.
- In its December 2011 Decision, the AUC determined that the credit market remained volatile and therefore decided not to employ an AAM for 2012. The AUC indicated that it was not prepared to preclude a return to some form of formula-based AAM in future once the capital markets had stabilized.
- The Newfoundland and Labrador Board of Commissioners of Public Utilities, in June 2012, approved an 8.8 percent ROE (which was not set by formula) for Newfoundland Power stating that this was within a range of reasonable values. The Board did not disavow or abandon the formulaic approach for future rate proceedings.

Concentric has not changed its position on AAMs and stated that: "periodic rate hearings remain the only reliable method for the determination of utility ROE's." However, Concentric noted that Canadian regulators have recognized that a sole reliance on simple relationships to government bonds cannot be relied upon to estimate ROE. Concentric points out that both Ontario and Quebec have incorporated utility bond spreads in their formulas and notes that this mitigates one fatal

weakness of past AAMs. Concentric views the two variable methodology utilized by Ontario as an improvement with a remaining concern being the lack of a specific link to the cost of equity , other than that conveyed by bond yields. (Exhibit B1-9-6, Appendix I, Concentric Update Report, pp. 1-4, 11)

The Commission Panel notes that both the OEB and the Régie formulas are variations of the model proposed by Dr. Booth and are discussed further in Section 6.2.2 below.

It appears that there is some acceptance by utility regulators in Canada of an AAM formula based on a two-variable model that uses the long-term Canada bond rate as a proxy for a risk free rate and a change in utility bond spreads as a proxy for credit risk. There is, however, reluctance in some jurisdictions to institute an AAM given the volatility of Canadian capital markets in recent years.

6.2.2 Submissions by Parties

AMPC/CEC

AMPC/CEC submit that the Commission abandoned the AAM in 2009 because it did not provide a fair return citing the following passage from the 2009 Decision: "the recent flight to quality has driven down the yield on long-term Canada bond yields, while the cost of risk has been priced upwards." Therefore, AMPC/CEC submit that the question for the Commission is, "what formula will allow it to return to an AAM, while ensuring that the results are fair in light of the current financial conditions and the conditions FEI might encounter going forward." (AMPC/CEC Final Submission, p. 62)

AMPC/CEC support a return to an AAM based on its contribution to regulatory efficiency because an AAM reduces the frequency of periodic ROE reviews. They note that FBCU have suggested that 3-5 years is a reasonable gap between comprehensive ROE reviews. AMPC/CEC points out that if the Commission agrees with this, an AAM would likely allow the reviews to be closer to five years rather than three, resulting in considerable efficiency benefits. (AMPC/CEC Final Submission, pp. 62-63)

Dr. Booth states that "The key problem with 'old' ROE adjustment models was that they *only* linked the ROE to the forecast long Canada yield. As a result, during the financial crisis the ROE formula

indicated declining ROEs while at the same time the utility cost of debt was increasing. An enhanced ROE formula has to deal with this, which can be done by incorporating the credit market adjustment I have used in my direct ROE estimates." (Exhibit C6-12, pp. 97, 100)

Dr. Booth recommends "an ROE adjustment model where ROE adjusts by 75% of the forecast change in long Canada bond yields and 50% of the change in the credit spread. This would be subject to a minimum forecast long Canada bond yield of 3.80% … Similar models are in use by the Régie and OEB." (Exhibit C6-12, p. 3) Dr. Booth selects 3.80 percent as the "floor" stating that this "is the lowest rate consistent with a normal cyclical low." (Exhibit C6-12, pp. 97, 100)
AMPC/CEC argue that Dr. Booth's enhanced two variable ROE formula addresses the concern with the old ROE formula that during periods of financial crisis the allowed ROE and utility borrowing costs move in opposite directions. They argue that Dr. Booth's formula obviates FBCU's concern that the AAM won't work because of the current unusual business cycle. The proposed 3.8 percent floor acts like a fixed rate ROE until the long Canada bond yields return to normal, and it provides an adjustment mechanism for periods when conditions are more typical. (AMPC/CEC Final Submission, p. 64)

ICG

Dr. Safir believes that an AAM for a limited number of years is appropriate because "It is simply not economically efficient to revisit the entire ROE setting mechanism annually" and also states that "the AAM is administratively efficient, resulting in significant savings by avoiding costly, annual rate hearings." In Dr. Safir's view, AAMs that reference long-term bond rates, such as the one previously used by the BCUC, are good ways to account for near term influences that affect a fair ROE. (Exhibit C4-9, pp. 36-37)

ICG observes that during the interim years between periodic cost of capital proceedings an AAM formula is more likely to result in an ROE that meets the FRS than no formula. It submits that the Commission should establish an AAM similar to the one discontinued by the Commission in 2009 that referenced long-term bond rates with a three year effective period. It would differ from the previous Commission AAM in that it would use a five year average for the forecast long-term Canada bond yield. (Exhibit C4-9, pp. 36-38; ICG Final Submission, p. 32; T7:1187)

ICG concedes that a multiple factor model may be more likely to meet the FRS than a single factor model, but given that the single factor model has been tested over a long period, it has been recommended to the Commission. (ICG Final Submission, pp. 32-33)

BCPSO

BCPSO submits that an AAM is beneficial because it ensures that the benchmark utility will not operate for more than a brief period of time with a higher than required ROE and therefore supports reinstatement of an AAM. (BCPSO Final Submission, pp. 19-20)

FBCU

FBCU does not support the return to an AAM. FBCU's main concern with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. They submit that an AAM relies on a formula with a limited number of inputs that could never capture the complex factors affecting ROE, and that an AAM likely relies on long Canada bond yields and corporate spreads, which are still affected by atypical market conditions. In addition, any formula relies on imperfect proxies. In their view, the application of the FRS requires a significant degree of analysis, market information, and judgment that evolve over time. Formula parameters are static and based on historic relationships and fundamental relationships may shift, leaving the formula out of touch with current market conditions. FBCU take the position that there is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one. This is supported by Ms. McShane who submits that the Commission should continue to address the appropriate cost [of capital] on a case-by-case basis: "There is no 'one size fits all' cost that should be determined by means of an interest automatic adjustment mechanism." (FBCU Final Submission, p. 153-156; Exhibit B1-9-6, p. 33; Exhibit B1-9-6, McShane Evidence, Appendix F, p. 7)

FBCU prefer to have the allowed ROE and capital structure set through a traditional process and remain constant between the periodic (three to five year) formal reviews, subject to events occurring that bring the results out of alignment with the FRS, which could result in an unscheduled full review process. This is preferable to having updates made on a basis that the FBCU believe is suspect. (Exhibit B1-20, BCUC 2.113.1)

FBCU argue that there is no efficiency gain associated with implementing the AAM, if there are to be periodic reviews. FBCU further argue that the regulatory burden associated with periodic cost of capital reviews is the same as that associated with periodic reviews with annual formula-driven ROE changes in the interim. FBCU also argue the FRS is best met in the intervening years until the next comprehensive cost of capital reviews by holding the ROE constant. (FBCU Final Submission, pp. 153-156)

FBCU further submit that "The rationale for why the Commission discontinued the AAM remains valid today. Meeting the Fair Return Standard is not optional." FBCU state that "All of the experts agree that we are still experiencing unusually low interest rates, and the ability of any AAM to produce fair results is far from certain [when such conditions exist]." (FBCU Final Submission, p. 153)

With respect to the positions taken by Dr. Safir and Dr. Booth, FBCU make the following submissions:

1. FBCU submit that Dr. Safir is proposing to return to an AAM that has already been rejected by the Commission, with the only difference being the starting point for measurement of changes in the forecasted long Canada bond yields (i.e., the use of the five-year average forecast). They cite Ms. McShane's statement that there is an inverse relationship between long-term government bond yields and the utility risk premium. FBCU also argue that Dr. Safir's use of a five-year average forecast Canada bond yield as the base line in the formula is problematic because it suppresses ROEs despite increases in long Canada bond yields. FBCU submit that while this five year average is intended to compensate for present unusually low interest rates, it would be better to postpone consideration of a formula, rather than implement a "quick fix" that artificially suppresses the ROE. (FBCU Final Submission, pp. 159-160)

2. FBCU submit that the AAM proposed by Dr. Booth is biased downwards. FBCU notes that the current long Canada bond yield is well below the 3.8 percent that Dr. Booth employs as the floor, and points out that while he expects rates to increase, he does not expect the forecast to rise above the 3.8 percent for at least three years. FBCU submit that the combination of rock-bottom forecast yields and a slow rise in interest rates has two implications. First, rock-bottom interest rates means that further declines are not likely. Second, any increase in the forecast long Canada bond rate will not result in an increased ROE. In addition, FBCU submit that the cross-examination of Dr. Booth indicates that he expects credit spreads to fall while the long term Canada bond yield remains below 3.8

percent, an expectation shared by Mr. Coyne. FBCU propose that the result of this will be a progressively lower benchmark ROE after 2013 if Dr. Booth's formula is employed. (FBCU Final Submission, pp. 160-161)

FBCU's position is that if the Commission requires an ROE AAM, it should seek to rectify the problems of the old formula. A new formula would address changes in the equity risk premium, and not solely changes in long Canada bond yields. Any adjustment factor would need to reflect sensitivity to change in bond yields to ROE. (Exhibit B1-9-6, pp. 27-29)

Corix

Corix submits that there is a continued flight to quality and a still increasing cost of risk, so an updated AAM is not appropriate at this time. (Exhibit B2-9, BCUC 1.2.1, p. 3)

6.3 Commission Determinations

6.3.1 Re-instituting an AAM

The Commission Panel does not take issue with FBCU's argument that an AAM formula with limited inputs cannot capture all of the complex factors affecting ROE and therefore, relies on imperfect proxies. However, at the same time, the Panel is of the opinion that the issue is whether the adoption of an AAM formula is better than the alternative, which is to do nothing as suggested by FBCU and Corix. In other words, while implementing an AAM formula may not be perfect, the question is whether it better satisfies the FRS than leaving the ROE static for a period of time or conducting frequent costly and time consuming ROE proceedings. The difficulty with leaving the ROE static over a three year or longer period is that financial markets continue to change and investors' needs continue to evolve. Therefore, in the view of the Commission Panel, implementing a mechanism to capture the impact of some of these changes is far superior to the alternative of doing nothing. Furthermore, as the AMPC/CEC submits, "if there are reasonable grounds to believe the mechanism is not producing fair results, the benchmark utility always has the option of asking for a review." (AMPC/CEC Final Submission, p. 64)

The Commission Panel does not disagree with FBCU's argument that the regulatory burden associated with periodic cost of capital reviews with or without an AAM is similar. However, we are

of the view that the likelihood of a requirement for more frequent ROE proceedings is reduced by having in place an AAM formula. Thus, the Panel is persuaded that the application of the AAM has the potential to contribute to regulatory efficiency.

Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the standard than taking no consideration of changes in the market over a three year period as suggested by FBCU. The AAM formula to be adopted and the timing of its use is addressed in Section 6.3.2.

6.3.2 Optional AAMs to be Considered

The Commission Panel acknowledges that interest rates have been atypical in recent years and have remained at historical lows. The historical AAM used by the Commission prior to 2009 relied exclusively on a single variable formula based on the long-term Canada bond yields as a proxy for risk free rates. This model was less than fully effective for utilities because the flight to quality kept interest rates abnormally low while the risk had been priced upwards. It could not assure that the FRS could be met in extended times of low interest rates.

As noted previously, Dr. Booth proposed a two-variable model that incorporates the traditional concept of tying the benchmark utility's ROE to the "risk free" long-term Canada bond yield, and also incorporates a credit market adjustment to reflect the relationship of ROE and credit risk within the utility sector. His model also utilizes a "floor" long-term Canada bond rate of 3.8 percent as the risk free proxy until such time as long-term Canada bond yields return to a more common level.

Concentric submits that any new AAM formula should address changes in the utility risk premium and not be based solely on changes to the long Canada bond yields. While it does not recommend a formulaic approach, it does provide several potential formulaic methodologies that could be used in British Columbia (Exhibit B1-9-6, Appendix I, 2010 Report, pp. 39-45)

In summary, possible options for re-instituting an AAM include:

- The single variable model used by the Commission prior to 2009 that was based on long Canada bond yields;
- The variety of approaches offered by Concentric (Exhibit B1-9-6, Appendix I, p. 11);
- Dr. Booth's two-variable model or a variation incorporating the long Canada bond yield, a floor level of long Canada bond yield to address the atypical low interest rates, and a metric to address credit spreads.

The Commission Panel recognizes the shortcoming of the single variable model used by the Commission prior to 2009 in that it fails to satisfy the FRS when interest rates continue at abnormally low levels. Accordingly, this model will not be considered.

While Concentric has explored a number of alternative formulas that could be used in British Columbia, the Commission Panel notes that none of these have been recommended by Concentric nor have they provided evidence as to their use and effectiveness in other jurisdictions. In addition, none of the interveners has expressed support for any of these. Given this lack of support and the lack of evidence to support their efficacy and relevance to British Columbia, the Commission Panel does not endorse any of the possible alternative AAMs explored by Concentric.

During cross-examination, Commission counsel asked Mr. Coyne of Concentric what advice he would give the Commission in terms of adjustments if the Commission were adopt an AAM similar to that of the OEB and the Régie. Mr. Coyne testified that a coefficient of 0.5 was a more accurate reflection of the historic relationship to long-term Canada bonds than 0.75. (T5:827)

Dr. Booth testified that he recommended 75 bps but that he could live with 50 bps and he did not believe that there would be a big impact. (T8:1622)

The Commission Panel is persuaded that a two-variable model similar to that proposed by Dr. Booth and currently utilized in Ontario is appropriate for application to the benchmark utility within British Columbia. (Exhibit C6-15, BCUC 1.44.5 attachment)

By utilizing the 50 percent adjustment of the change in the long-term Canada bond yield as a proxy

for risk free rates, it recognizes the relationship between ROE and risk while moderating the level of change resulting from any volatility in the long-term Canada bond rate. In addition, by utilizing the 50 percent adjustment in the change in the utility bond spreads, it recognizes the relationship between credit risk and ROE in the utility sector and moderates volatility in utility bond spreads. And finally, by utilizing a 3.8 percent floor for the long Canada bond yield, it recognizes the atypical relationship between ROE and cost of risk in periods of unusually low interest rates. Further, the application of similar models within both Ontario and Quebec supports it usefulness and acceptance within other Canadian regulatory jurisdictions.

Given the advantages, the Commission Panel adopts a two variable model AAM to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. The AAM formula will operate until December 31, 2015. The implementation of the model is subject to conditions outlined in Section 6.3.3. The formula will initially utilize the 8.75 percent ROE as determined in Section 5.7 as the base ROE.

The formula to be used and the basic method to determine the changes in long Canada bond forecast and the changes in utility bond spread are provided as follows:

$$ROE_1 = \text{Base ROE (8.75\%)} + 0.50 \times (LCBF_t - \text{BaseLCBF}) + 0.50 \times (\text{UtilBondSpread}_t - \text{BaseUtilBondSpread})$$

Where:

$LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.

UtilBondSpread_t is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

6.3.3 Impact of a 3.8 percent Floor

FBCU has argued that the AAM proposed by Dr. Booth is biased downwards. The Commission Panel agrees that the potential for a downward bias does exist.

Dr. Booth has recommended that any change in the ROE be subject to a minimum forecast bond

yield of 3.8 percent as this is the lowest rate which is consistent with a normal cyclical low. The Commission Panel accepts this as reasonable since it is the risk free rate for the CAPM ROE as determined in Section 5.2.

With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. **To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.**

The Commission Panel has considered Concentric's submission that Dr. Booth did not specify an objective bond forecast to reference as a starting point. We are of the view that the potential for downward bias will continue if attention is not paid to setting appropriate base rates for the formula. Therefore, the Commission will seek submissions from the parties with respect to determining appropriate base levels and developing an effective methodology for deriving the inputs to the formula.

The Commission Panel understands that the conditions placed upon the implementation of the AAM

formula may well result in the 8.75 percent ROE being in place for the term of this Decision ending December 31, 2015. However, in consideration of the FRS, the Panel is of the view that this is appropriate.

FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015.

7.0 COST OF CAPITAL – SMALL UTILITIES

7.1 Introduction

When the Commission initiated the GCOC Proceeding, it identified the Affected Utilities, which included FEI and other FortisBC gas and electric utilities, PNG and Corix. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. In addition, the Commission identified Other Utilities that "may wish to participate in the GCOC Proceeding." This list included among others:

- Big White Gas Utility Ltd. and Sun Peaks Utilities Co. Ltd.;
- Central Heat Distribution Ltd.;
- Dockside Green Energy LLP;
- Hemlock Valley Electrical Services Limited; and
- River District Energy Limited (River District).

The recent emergence of thermal energy services (TES) in British Columbia has resulted in the creation, over the last few years, of a number of new on-site thermal energy systems and district energy systems, which are subject to the Commission oversight. For instance, FortisBC Alternative Energy Service Inc. (FAES), an affiliate of FEI and a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), now owns and operates or is proposing to develop the following regulated TES projects:

- Delta School District Number 37;
- Tsawwassen Springs Development;
- PCI Marine Gateway;
- TELUS Garden Thermal Energy System; and
- Kelowna District Energy System.

Key purposes identified by the Commission Panel in its Final Scoping Document were to establish:

(i) a method to determine the appropriate cost of capital for a benchmark low-risk utility in BC and how the Benchmark ROE will be reviewed and/or adjusted;

(ii) a generic methodology or process for determining each Affected Utility's cost of capital in relation to the benchmark utility's cost of capital; and

(iii) a framework for determining the appropriate cost of capital for other smaller utilities in the province.

Related to this framework, the scope of the proceeding included the following key activities:

(i) establish a generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility;

(ii) in certain circumstances, develop a methodology to establish a deemed capital structure and deemed cost of debt, particularly for those small utilities without third-party debt, which would involve setting a methodology on how to calculate a deemed interest rate.

(Exhibit A-3, Appendix B to Order G-47-12)

The Commission Panel also requested submissions regarding Stage 1 and Stage 2 review. The FBCU submitted it would be most efficient to break the process down into three groups which would be handled separately: one for the FBCU, a second for the PNG and a third for micro utilities including Corix and FAES and others. (Exhibit B1-22, pp. 10-11) By Order G-148-12, the Commission Panel directed that a Stage 2 will be added to this GCOC proceeding with the schedule to be determined prior to the end of Stage 1. (Exhibit A-21)

Transition to Stage 2

The purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by the Affected and Other Utilities as compared to the benchmark utility FEI. Based on this assessment the Panel will then determine how the risk differentials will impact the capital structures and the allowed ROE for these utilities.

The Panel acknowledges the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for TES systems, irrespective of the provider. This would include FEI and FAES's Thermal Energy Services, and similar systems to be operated by developers or providers like Corix. (Exhibit B1-9, p. 34) The Panel also notes the previously mentioned FBCU suggestion about dividing the Stage 2 process into three groups.

In anticipation of Stage 2, this section addresses issues related to the framework for determining the cost of capital for the smaller utilities, including all new small TES utilities. The appropriate method to determine interest rates for deemed debt will also be addressed. In this Decision, the definitions of "small utilities" and "micro utilities" are used interchangeably.

7.2 Framework for Establishing an Appropriate Cost of Capital – Equity Risk Premium

7.2.1 Is Size a Risk Factor in ROE and Capital Structure Determination?

Ms. Ahern, the expert witness for Corix states "it is conventional wisdom, supported by actual returns over time, that smaller companies tend to be more risky, causing investors to expect greater returns as compensation for that risk." Ms. Ahern further explains that smaller companies, for instance, face more risk exposure to business cycles and economic conditions, both nationally and locally. Similarly, the loss of revenues from a few larger customers would have a greater effect on a small company than on a much larger company with a larger, more diverse customer base. Moreover, smaller companies are generally less diverse in their operations as well as experiencing less financial flexibility. (Exhibit B2-7, pp. 6-7)

Ms. McShane, the expert witness for FBCU states that in the assessment of investment risk, size has two dimensions that should be considered in determining a utilities common equity ratio and ROE:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility.
2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Ms. McShane also points out that debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. (Exhibit B1-9, Appendix F, p. 134)

PNG submits "there was little to no evidence submitted that suggested or countered that size was not a significant factor." While precedents and empirical studies exhibit a broad range of explicit company size adjustments (150-436 bps), which introduces a degree of subjectivity, PNG further submits that "Stage 1 evidence concerning size as an independent factor was relatively uncontested." (PNG Final Submission, p. 13)

7.2.2 Stand-Alone Principle

Both Ms. Ahern and Ms. McShane reaffirm the importance of the stand-alone principle, which is "a cornerstone of Canadian utility regulation with a history dating to at least 1978." (Exhibit B1-9, Appendix F, p. 10, B2-9, BCUC 1.4.7) Therefore, even if a small utility is owned by a larger parent company, there should be no impact on the determination of the small size utility ROE and capital structure. Each utility within the Commission's jurisdiction should be evaluated on a stand-alone basis.

Ms. Ahern further states there is ample academic evidence that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. She submits "it is the use of funds invested and not the source of those funds which gives rise to the risk of any investment." She refers to the text of Brealey and Myers, which notes "Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put." (Exhibit B2-7, p. 7)

7.2.3 Academic Evidence of the Size Effect in Literature

In her filed evidence, Ms. Ahern provides additional examples of the academic literature, where the risk effects of a company's size on the investor required return is addressed:

Eugene F. Brigham, *Fundamentals of Financial Management:*

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-

> firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.
>
> (Exhibit B2-7, PMA-3, p. 4)

Giacchino and Lesser, *Principles of Utility Corporate Finance:*

> In general, smaller firms face greater financial risk than do large firms... Generally, firm size is measured in terms of total capitalization (i.e., the market value of a firm's equity). Empirical studies have typically found that small firms typically have higher returns over the long run than larger firms. (Exhibit B2-7, PMA-4, p. 3)

Fama and French, in *"The Capital Asset Pricing Model: Theory and Evidence,"* Journal of Economic Perspectives, note that size is a risk factor which must be reflected when estimating the ROE:

> ...the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market returns and are priced separately from market betas. (Exhibit B2-7, PMA-5, p. 14)

Based upon this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect of size on the rate of return on common equity.

Marc Reinganum, *"A Possible Explanation of the Small Firm Effect,"* The Journal of Finance:

> While the OLS estimates seem to understate the betas of small firms, the excess returns not explained by the misestimation could easily exceed twenty percent per year on average. Thus, one can conclude with confidence that the small firm effect is still a significant economic and empirical anomaly. (Exhibit B2-6, PMA-6, p. 9)

From her academic research, Ms. Ahern concludes that:

- The specific, unique risks of the investment (e.g. utility) must be reflected in the rate of return; and
- The size of an investment (e.g. size of the utility) is one of those unique risk factors for which investors must be compensated. (Exhibit B2-7, pp. 10-11)

7.2.4 Empirical Evidence for the Risk Effects of a Company's Size on the Investor's Required Rate of Return

Studies on small size and returns have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historical returns for companies of different sizes. Ms. McShane and Ms. Ahern state the analyses indicate that small companies tend to exhibit higher betas than larger companies. Two empirical studies reviewed by Ms. Ahern are:

Morningstar/Ibbotson Size Premium Study (Firm Size and Return)
Ibbotson SBBI – 2012 Valuation Yearbook

This study constructs decile (10) portfolios of the companies contained in the NYSE, AMEX and NASDAQ. Ms. Ahern suggests that the study can be used to determine the approximate risk premium due to size for a specific utility over the benchmark utility return. This is done by comparing the size premium appropriate for the decile in which the benchmark utility would fall based on the estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization.

	Decile	**Market Capitalization ($Millions)**	**Size Premium (%)**
Benchmark Utility	5	2,246 (average)	1.74
Micro-Cap	10	92	6.10
Size Premium			**4.36%**

(Exhibit B2-6, PMA-8, Table 7-1 and 7-5)

Duff & Phelps Size Study and Risk Study

The Size Study analyzes the relationship between equity returns and company size in a similar manner as the Morningstar Study. It could also be used to determine the magnitude of any necessary risk premium due to the size of a specific utility relative to the benchmark. In addition to presenting risk premia and size premia for 25 size-ranked portfolios using the traditional market

capitalization measure, this study also considers seven other measures of company size, including book value of equity, 5-year average net income, market value of invested capital, total assets, 5-year average EBITDA, sales and number of employees. (Exhibit B2-7, PMA-9, p. 30)

The Risk Study is an extension of the Size Study. The main difference is that while the Size Study analyzes the relationship between size and return, the Risk Study analyzes the relationship between fundamental risk measures (based on accounting data) and return. These are called "fundamental" measures of a company risk to distinguish these risk measures from a stock market-based measure of equity risk such as betas. (Exhibit B2-7, PMA-9, p. 65)

Corix provided a calculation of the size risk premium for micro utilities over the benchmark based on the Duff & Phelps Study. This resulted in a 3.89 percent risk premium as opposed to the 4.36 percent size premium based on the Morningstar Study. (Exhibit B2-8, Attachment to BCPSO 1.1)

7.2.5 Regulatory Support for Size Premium

Ms. Ahern provided only one example of a jurisdiction which has adopted the size premium concept. She cites the Florida Public Service Commission (FL PUC), which adds for small water utilities a bond yield differential, a 50 bps private placement premium and a 50 bps small utility risk premium to the ROE based upon the index of natural gas utilities. Regardless, Ms. Ahern recommends that the size risk of each utility be measured in accordance with the Morningstar/Ibbotson and the Duff & Phelps studies. Specifically, Ms. Ahern states "all of these risk premium spreads should then be averaged and through the exercise of informed expert judgement, a determination of the appropriate risk premium to be added to the benchmark utility return on equity to reflect the size risk of the utility/project relative to the benchmark utility." (Exhibit B2-9, BCUC 1.12.1; Exhibit B2-8, BCPSO 1.2.1)

In responses to IRs and during cross-examination, Ms. Ahern made it clear that she is not recommending any particular amount of a size premium to be adopted by the BCUC but is simply providing testimony for the purpose of establishing a framework. (T6:1128) Similarly, Ms. Ahern states the 4.36 percent risk premium shown in the example would only represent the upper limit of a size premium above the allowed benchmark ROE due to small size. Where in the 10th decile, Corix or any of its projects fall needs to be evaluated to determine the exact risk premium it would

propose. Corix stated it has not yet undertaken a comprehensive study of the appropriate size risk premium above the benchmark for each of its projects and indicated that such a study will be conducted in the next phase of the GCOC proceeding. (Exhibit B2-9, BCUC 1.13.2)

Ms. Ahern acknowledged that based on her experience the regulatory support for a specific size premium has been minimal and that ultimately any risk premium, whether it is linked to business risk in general or size specifically, is a matter of informed expert judgment. (T7:1278-1284) Further, Ms. Ahern could provide only seven cases out of over 200 regulatory proceedings where she has been involved that resulted in an allowed size adjustment. Yet, in a response to an undertaking, it appears that only two of those seven cases *specifically* reference "size" in the determination of the overall ROE and only one case granted a specific size premium. (Exhibit B2-14) Furthermore, the Panel notes that Ms. Ahern had recommended only modest size adjustments in the range of 25-50 bps in all those seven cases.

Ms. McShane concludes the empirical study findings indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual utilities in British Columbia. (Exhibit B1-9, Appendix F, p. 136)

Commission Determination

Stand-Alone Principle

The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a "new" utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.

The Size Premium

The Panel has considered the evidence on record regarding the academic literature on the size effect as well as the empirical evidence for the risk effects of a company's size on the required rate of return. Noteworthy is the lack of regulatory support for the recognition of a small size risk premium. Finally, the Panel notes the requirement for on-going exercise of informed judgment by both the Commission and experts retained by the utilities, which was acknowledged by Ms. Ahern.

As a result, the Panel recognizes the academic literature and empirical studies seem to support the importance of size in explaining returns. At the same time, however, the evidence presented does not indicate how adjustment for size should be implemented.

Accordingly, the Panel determines that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. Utilities are encouraged to use other methodologies or approaches to justify their risk differential in relation to the benchmark. The Panel has not been sufficiently persuaded to put any weight to the empirical studies reviewed to date.

The Panel notes that the Commission developed a risk matrix that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. The "size" factor is one of the risk factors included in the matrix. **The Panel recommends that the small utilities use this risk matrix attached as Appendix B to Order C-1-13 of the TELUS Garden Decision[9] in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the benchmark ROE**. For convenience, the risk matrix is attached in Appendix E of this decision. Small utilities, other than TES, can modify this matrix to facilitate a similar comparison of their own short and long-term risks to those of FEI.

The Panel is cognizant of the on-going Phase 2 of the Alternative Energy Solutions (AES) Inquiry,[10] which involves development of a regulatory framework for dealing with small TES utilities. This evolving process will further influence the nature and content of future TES applications.

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[9] Certificate of Public Convenience and Necessity Order C-1-13 and Reasons for Decision dated February 5, 2013, regarding FAES Telus Garden Thermal Energy Services

[10] In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Solutions and Other New Initiatives

7.3 Guiding Principles for Setting Deemed Capital Structure and Deemed Debt

7.3.1 Determination of Deemed Capital Structure

The Commission deems an appropriate common equity ratio for the utility. The resultant debt ratio is simply the residual between 100 percent and the deemed equity ratio. However, the deemed component typically incorporates actual debt issues where rates can be objectively observed and determined. In some cases, the utility manages its actual financing to mirror the deemed debt/equity ratio.

Ms. McShane explains the actual debt issues may consist of issues that have been made directly into public markets; they may be private placement to third party institutions such as bank or insurance companies, or they may be non-arms length issues between a utility and affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with rates that are based on market conditions. When the parent company issues debt, the subsidiary can enter into an arrangement with the parent for a specific portion of that debt issue, with the same terms as the third-party issue. Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent. (Exhibit B-1-9-6, McShane Evidence, Appendix F, p. 121)

7.3.2 Criteria for Setting the Deemed Capital Structure

Ms. Ahern, the Corix expert, states that an appropriate deemed capital structure should:

- be reasonable relative to or consistent with the average capital structure of the particular utility industry;
- reflect the specific utility's unique risks, including its relative size;
- be consistent with bond rating agency metrics; and
- provide the opportunity for the utility to earn a reasonable and fair rate of return, given its unique risks, e.g., size etc.

(Exhibit B2-7, p. 19)

Ms. McShane provides general principles that should be observed when setting the ROE and common equity ratio for utilities, regardless of size:

- The combination of ROE and common equity ratio awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility;
- The overall return awarded to each utility should be comparable, on a risk adjusted basis, to the overall return awarded to the benchmark utility;
- The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some utilities many not actually have a credit rating; and
- There is a trade-off between equity ratio and ROE. For example, if a utility is not fully compensated for higher business risk than that of the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility. (Exhibit B1-9-6, p. 129)

7.3.3 When Is Deemed Debt Appropriate?

The FBCU state the deemed debt is appropriate for small utilities in cases where raising debt is inefficient. For example, a separate division or class of service within a larger regulated utility can contain a stand-alone project. Similarly, a regulated utility subsidiary/affiliate within a larger corporate organization can face circumstances where either:

(i) The high cost of debt issuance relative to the size of the issue makes the effective debt cost higher than it would be otherwise; or

(ii) The size of the utility precludes it from accessing appropriate debt terms.

The FBCU further state that the assessment as to whether deemed debt is appropriate and efficient should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. Finally, FBCU state "it is reasonably clear that deemed debt would be appropriate for FEW (a separate legal entity), the Fort Nelson Division of FEI, and FAES." (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.1, 1.140.2)

7.3.4 Setting the Appropriate Deemed Debt Rate and Term

The FBCU state that deemed debt rates and duration should reflect the particular circumstances of each utility. Utilities for which a deemed cost of debt might be appropriate may have differing profiles; FEW, for instance, is not the same as one of FAES's TES projects or Corix's UniverCity project. The appropriate term of debt may also vary even among projects with a broadly similar risk profile. (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.2)

Ms. McShane submits as a general proposition that the term should reflect the long-term nature of the assets and offers the following additional considerations:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term for the debt.
2. The higher the risk of the specific operation, the less their ability would be to obtain "real" debt on a long-term basis; i.e., on terms longer than 10 years. The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.
3. The appropriate term for the deemed debt also depends on the state of the capital markets.

Ms. McShane concludes that the individual utilities' circumstances may differ in terms of risk, the funding requirements and appropriate terms of debt. Accordingly, she recommends that the Commission continue to address the cost of deemed debt for each utility separately, on a case-by-case basis. In her view, there is no "one size fits all" cost mechanism. (Exhibit B1-9-6, pp. 123-124)

Commission Determination

Before addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission Panel wishes to reaffirm certain principles for the Stage 2 GCOC proceeding framework.

(i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

(ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;

(iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and

(iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

Related to the issue of deemed capital structure and deemed debt are two key questions that the Stage 2 GCOC proceeding must address more comprehensively:

1. Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
2. How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

7.4 Appropriate Portions of Short-Term and Long-Term Debt in the Deemed Capital Structure

In British Columbia, in some of the more recent TES Decisions, the Commission has considered deeming a portion of overall debt to short-term debt. To date no determination has been made to put this into effect. However, the Panel notes that the OEB has officially deemed a standard four percent proportion of short-term debt component for utilities under its jurisdiction for reasons that it outlined in its 2006 Decision:

(i) All utilities actually use some short-term debt;

(ii) Short-term debt is generally less expensive than long-term debt and provides greater financing flexibility; and

(iii) While actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of distributors regulated by the OEB.[11]

[11] OEB, Report of the Board on Cost of Capital and 2nd Generation incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 9-10

In 2009, the OEB reaffirmed this practice for natural gas distributors as well. It also updated its methodology to estimate the deemed short-term debt rate. (Exhibit A2-21, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, EB-2009-0084)

Ms. McShane states there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt. She notes that annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues. Based on her filed evidence she further states that the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1 percent to 2 percent. Her review of 2010 data for Ontario electricity distributors indicated that the average and median actual short-term debt ratios were at 2.9 percent and 0.4 percent respectively. (Exhibit B1-9-6, pp. 125-127)

Ms. Ahern states that conceptually the maturity of the debt capital should match the life of the assets being financed. But when the inclusion of short-term debt is optional, its inclusion should be based upon several criteria:

- If its use is sporadic and hence, volatile, it should not be included in the capital structure. However, if its use is consistent and especially at a significantly high level, it is likely financing rate base and possibly should be included;
- If its use is seasonal and self-liquidating, e.g., financing short-term inventories of natural gas in anticipation of heating season, it probably should not be included;
- If short-term debt is financing working capital, it should be included;
- If it is used as bridge financing until permanent financing can be put in place it should be included at the expected cost rates of that permanent financing; and
- If the short-term debt financing construction projects and if the Construction Work In Progress (CWIP) are included in rate base the short-term debt should be included. (Exhibit B2-7, pp. 23-24)

The FBCU provided information showing actual percentages of short-debt for FEI, FEI – Fort Nelson, FEVI, FEW, and FortisBC Inc. for the 2002-2012 period. While there has been significant fluctuation over the years, the average percentages for the period as a share of capital structure amounted to

5.28 percent, 8.58 percent, 10.77 percent, 13.10 percent and 5.27 percent for each respective utility. (Exhibit B1-24, BCUC 2.189.1, 2.189.2)

Commission Determination

The Commission Panel finds it as an accepted fact that all utilities use some short-term debt financing. The FBCU IR responses clearly support this. While there are varying reasons for its use, the evidence demonstrates that, on average, utilities always carry a small portion of short-term debt in their capital structure. The construction work in progress, due to its nature, is often financed by short-term debt.

Accordingly, the Commission Panel finds it reasonable and prudent to include a deemed component of short-term debt in the capital structure for all small utilities without third-party debt to reflect reality. To establish the percentage of short-term debt to be deemed, the Panel has considered testimony of Ms. McShane, FBCU IR responses and the OEB established practice in Ontario. **While acknowledging that there is no correct amount, the Panel concludes that a four percent component for deemed short-term debt provides a reasonable proxy as it is the midpoint of the range of actual short-term borrowing.**

7.5 Setting the Deemed Interest Rates

7.5.1 Deemed Interest Rate for Long-Term Debt

Parties acknowledge that there are at least three reasonable options for determining the deemed interest rate applicable to a small utility without third-party debt. These options are summarized below.

FBCU Option 1:

Step 1: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. The FBCU submit this approach is consistent with the stand-alone principle, and is how FEW has financed the debt component of its capital structure. (Exhibit B1-9, pp. 29-30; Exhibit

B1-20, BCUC 1.141.1, 1.141.5, 1.144.2) A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 123; Exhibit B1-20, BCUC 1.147.1)

Step 2: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms. (Exhibit B1-9, p. 30)

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond. (Exhibit B1-9, p. 30; Exhibit B1-24, BCUC 1.141.5.2; Exhibit B1-24, BCUC 2.188.2, 2188.3)

FBCU Option 2:

Ms. McShane identified an alternative approach to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and interest rate based on an approved capital structure. Currently, FEI-Fort Nelson debt is deemed and the rate is the embedded cost of debt. (Exhibit B1-20, BCUC 1.141.1, 1.141.6) The FBCU submit that this is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits of issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity raising the debt will be able to recover its actual incurred cost of debt. (Exhibit B1-20, BCUC 1.148.8)

Corix Option:

Corix supports FBCU's recommendation to apply one benchmark credit spread for small utilities to provide regulatory efficiency. To align with the proposed method, the benchmark credit spread would reflect the spread for BBB and BBB (low) rated debt relative to the underlying 10 year GoC bond yield and would reflect incremental risk of small utilities. Corix states that with the benchmark set for small projects, project stakeholders and interveners can then justify any variances from the benchmark depending on the risk exposure. (Exhibit B2-9, BCUC 1.26.3, 1.27.1, 1.46.5, 1.46.7, 1.46.11)

Commission Staff Option:

This option was raised in order to account for the scarcity of BBB-rated utilities in Canada that can be used as proxy, and for the possibility that utility ratings can be changed.

Step 1: Obtain the yield on an appropriate GoC bond as the benchmark.

Step 2: Assign a credit rating to the stand-alone utility/project based on an assessment of financial and business risk (e.g., BBB, other)

Step 3: Obtain the bond yield (credit) spread between GoC bond and a high grade utility (A or A low) and add it to the rate in Step 1.

Step 4 Add a premium, if required, to the credit spread in Step 3. This premium will be calculated as the credit spread between high grade utility bonds (A or A low) and utility bonds of the credit rating estimated in Step 2. The use of historical data (e.g., two most recent years) to have more data points could be considered. (Exhibit A2-43; Exhibit B1-20, BCUC 1.141.9; Exhibit B1-24, 2.188.6; Exhibit B2-9, BCUC 1.26.6)

The FBCU submits it is generally supportive of the Staff option but raised one concern. Ms. McShane cautioned that for any method involving the use of credit rating proxy companies, care should be taken to employ reasonable credit ratings. She re-emphasized that an appropriate credit for small utilities would be BBB to BBB (low), as the inherent risk of small size would preclude them from achieving higher ratings:. "As it is much more likely that the small utility would be BBB on a standalone basis, it makes sense to use a BBB yield as the benchmark to begin with rather than using A-rated proxies." (FBCU Final Submission, pp. 164-165; T5: 680-681)

Commission Determination

The evidence and Final Submissions suggest that setting the deemed interest rate is not a very controversial issue. However, each option reviewed has advantages and disadvantages. The Panel also notes that similar approaches have been adopted in number of recent TES Decisions. For example, BBB-rated proxies were used for the Delta School District Number 37 and Tsawwassen Springs projects.

The Commission Panel has already found that the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis. Based on this the Panel recommends that on a go-forward basis the FBCU's Option 1 be used as a guideline for setting the deemed debt rate. The Panel is cognizant of the refinement proposed by Commission Staff to account for the scarcity of BBB-rated utilities in Canada that can be used as a proxy. Should this become a major issue in the future, the Commission can consider switching to use the Commission Staff Option as the guideline.

Because the deemed long-term debt by definition is set for a fixed term, the Panel finds that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt. The impact of the rate change could be considered a subsequent revenue requirement review.

However, to allow some flexibility, the utilities will have an option to apply for a rate adjustment in accordance with the following reopener-criteria:

- **A measurable change in market conditions**
- **A measurable change in actual debt costs**

The Commission will consider each application for a rate adjustment on a case-by-case basis.

7.5.2 Deemed Interest Rate for Short-Term Debt

The FBCU state the basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate determination. It would be based on indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate (CDOR). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances (BAs), which reflect the short-term benchmark rate plus the company's applicable credit spread. (Exhibit B1-9, p. 31) In response to IRs, the FBCU clarified that quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer. (Exhibit B-20, BCUC 1.44.2, 1.44.3)

Ms. McShane states that three-month BAs are also a common benchmark for establishing the cost of short-term debt for utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 127-128) In response to IRs the FBCU confirm that either the 3-month CDOR or 3-month BA rate is reasonable for setting the short-term rate. Regarding the indicative credit spread quotes, the FBCU state the following approach used by the OEB is reasonable: the OEB obtains up to six quotes from banks. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes obtained. (Exhibit B1-20, BCUC 1.144.4) The FBCU submit that the OEB formulaic approach is an efficient and transparent way of estimating a deemed short-term debt rate. However, the FBCU stress that the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally corresponds to long-term credit ratings in the A category; i.e., higher than would be applicable to the small utilities. To overcome this problem, the FBCU suggest using a more reasonable short-term credit rating, one that would correspond to a BBB/BBB (low) on the long-term rating scale. (Exhibit B1-20, BCUC 1.144.5, 1.144.5.1)

Commission Determination

The Commission Panel recommends that small utilities use either the 3-month CDOR or 3-month BA rate as a basis and obtain 3-4 quotes to establish the credit spread for the purpose of setting the deemed short-term interest rate. Because it is highly unlikely that small utilities, especially the TES utilities/projects, will have frequent revenue requirement reviews, the Panel finds that there is no requirement for an annual adjustment mechanism. **The short-term rates are to be reset at the time of the revenue requirement review only.**

8.0 OTHER MATTERS

8.1 Reliance on Less Complex Financial Methodology

Expert witnesses in this proceeding expressed reluctance to use more complex models that could improve understanding and/or estimating the cost of equity. For instance, Ms. McShane states: "I think it's reasonable to try to capture these other factors. I know that it's been difficult to have regulators accept the Fama/French type models ..." (T5:721)

In response to a question from Commissioner Giammarino, Dr. Vander Weide expressed similar concerns:

> **COMMISSIONER GIAMMARINO:** "And [Fama/French] suggest that maybe the future is in an inter-tempo CAPM, that has multi factors. And that would allow for changes in the opportunities – the investments that are available to investors. Did you consider that as an alternative?" (T6:1103)
>
> **DR. VANDER WEIDE:** "That would certainly be an alternative, but from my years in testifying on the cost of capital, I have realized that there are two qualities that make a model present reasonable evidence. One is that it's -- you can estimate the inputs to the model reasonably well, and two, it has to be reasonably easy to understand. So that one can judge the model in the context where everyone doesn't have Ph.D.s in finance or economics. And once you get into dynamic capital asset pricing models, to me that's getting into a level that's too complicated for discussion in a public forum." (T6:1103)

Although Dr. Booth added a credit spread adjustment to his CAPM analysis, he also expressed a similar sentiment about adding further factors to his CAPM, as shown by the following exchange:

> **COMMISSIONER GIAMMARINO**: …there is sort of a well-established set of suspects. You've looked at one.
>
> **DR. BOOTH:** Correct.
>
> **COMMISSIONER GIAMMARINO:** So why not look at all?
>
> **DR. BOOTH:** Two reasons. First of all, with all due respect to the Commission, it's a question of getting things to the Commission in an understandable way through cross-examination. And KISS works. That a simple way of looking at these things, I think, makes sense. The only time,

for example, I saw a company put forward the Fama French model was before the Gaz Métro. And the witness had a real tough time with the more complicated model. And the Régie was very reluctant to adopt a more complicated model.

COMMISSIONER GIAMMARINO: Right.

DR. BOOTH: So when you get down to conditioning, you're absolutely correct. You think about Chandrell and Ross, and you think about economic factors affecting security returns, you can go to more measures. Does the addition of more measures make the testimony more saleable to a Commission? And the answer to that is generally no. It may make it more saleable in an academic seminar but it's easier, I think, to pick on one thing that people can relate to – credit spreads – that was picked up in most of the hearings in 2009, which seems to make sense, and seems to be consistent with the academic literature, than to go through a more complicated model with term structure, yield parameters, dividend yields or other conditioning variables. So, I pick one, the credit spread. (T8:1658-59)

The Commission Panel accepts that evidence should meet some basic criteria. For example, expert witnesses must have confidence in their estimates; and the evidence must be understandable to the Panel, ideally for all parties involved. The Panel is, however, concerned that experts pay undue attention to prior assessments of the limits of what the Commission will understand and/or accept. While evidence put forward should be as helpful as possible to a Panel dealing with the difficult task of determining the appropriate rate of return and capital structure, it should reflect the expert's best judgment about the state-of–the-art methodology, which should in turn be presented in an understandable way.

It is the Commission Panel's opinion that the purpose of a cost of equity model is to provide structure to the discussion of 'what is a fair rate of return.' Models used to fulfill this purpose provide structure and clarity, and in turn provide a basis for determining the truth of any particular assessment. Models are abstractions and, by definition, imperfect representations. As a result, it is up to the Panel to decide how much confidence it should put in various models that have unrealistic assumptions and do not explain returns perfectly. The Panel must also understand where judgment needs to be applied to the output delivered by these models.

Specifically, in Section 5.2.1, the Panel identified some of the weaknesses related to the adjustments to the CAPM. In particular, the experts expressed reluctance to include additional potential extensions to the CAPM because they were perhaps "too complex" to the Panel. This in turn leaves

open what results other extensions could imply. Similarly, in the beginning of Section 5.2 the Panel identified the lack of global perspective in assessing the investor's portfolio. A more clear set of principles, including a definition of FEI's investors' portfolios (i.e., Global, North American, Canadian) would have been valuable. Accordingly, the Panel invites more comprehensive evidence on these topics in the future.

The Commission Panel believes that one of the roles of the expert is to guide the regulator in evaluating the trade-off between the complexities of the structures needed to evaluate arguments versus the reliability of the structures. This trade-off is at the heart of cost of capital hearings. As this trade-off evolves constantly, the testimony should evolve with it.

8.2 FEI - The Benchmark Utility

Based on the evidence related to long and short-term risk before the Commission Panel we are in agreement with describing FEI as the "benchmark utility" rather than a "low-risk benchmark utility." While the Panel has determined that the level of risk is somewhat less in a number of areas than those which existed at the time of the 2009 Decision, there has been little change in many areas. Therefore, we are of the view that describing FEI as low-risk would not be appropriate. Accordingly, for the purposes of Stage 2 of the GCOC, FEI will be referred to as the benchmark utility. **The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

The issue as to whether FEI is a pure-play gas distribution received little direct attention beyond the October 4, 2012 procedural conference. However, the Commission Panel has considered the issue in the context of the level of throughput related to alternative energy initiatives. It appears that FEI's forecasted throughput related to alternative energy initiatives is relatively small. Under cross-examination, FBCU witness, Mr. Stout with reference to natural gas transportation initiatives stated:

> "...we forecast two and a half to three petajoules in 2017. I think even if you go to some volume that's in the 10 to 15 petajoule range, it's still less than 10 percent of the throughput of the system, say 5 to 10 percent of the total throughput". (T3:317)

Based on Mr. Stout's testimony, the Commission Panel accepts that FEI at this point in time is primarily a pure-play gas distribution utility.

While Stage 1 of the GCOC proceeding has been mainly concerned with determining an appropriate cost of capital for the benchmark utility, Stage 2 will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk. The Commission Panel considers that it is feasible that a stand-alone public utility may face overall business risks that are either higher, lower or the same as the benchmark utility.

The primary factors that have influenced FEI's long-term risk have been identified and addressed in Section 4.2. In addition, we have further identified and made determinations upon FEI's short-term risk. In Stage 2 of the GCOC, the public utilities, where appropriate, will be required to describe how they differ from the benchmark utility on these and any other risk factor as it relates to them. In addition, in Section 7.2.5 the Commission Panel has described a risk matrix (included in Appendix E) as a tool for the small utilities (especially the TES utilities) to further assist in justifying their case for an appropriate capital structure and risk premium.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

Original signed by:

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

R. GIAMMARINO
COMMISSIONER

Original signed by:

M.R. HARLE
COMMISSIONER

Original signed by:

L.A. O'HARA
COMMISSIONER

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Generic Cost of Capital Proceeding

BEFORE: D.A. Cote, Commissioner/Panel Chair
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner
R. Giammarino, Commissioner

May 10, 2013

O R D E R

WHEREAS:

A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt;

B. Appendix C to Order G-20-12 divided public utilities into two categories for the purpose of the proceeding: "Affected Utilities" and "Other Utilities;"

C. FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc. (FortisBC)[collectively (FBCU)]; Corix Multi-Utility Services Inc. (Corix); and Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG) registered as Affected Utilities. The British Columbia Hydro and Power Authority (BC Hydro) and the River District Energy (RDE) registered as Other Utilities;

D. Among the Interveners who registered for the proceeding, the Association of Major Consumers of BC (AMPC), British Columbia Pensioners' and Seniors' Organization (BCPSO), Commercial Energy Consumers (CEC) [collectively B.C. Utility Customers], and the Industrial Customers Group of FortisBC Inc. (ICG) actively participated;

E. By Order G-47-12 dated April 18, 2012, the Commission issued the Final Scoping Document for the proceeding. The Scoping Document sets out the purpose and the scope of the proceeding. Matters within the scope of the proceeding included, among others, the appropriate cost of capital and its effective date for a benchmark low-risk utility, the establishment of a benchmark ROE, the consideration of an automatic adjustment mechanism, and the deemed capital structure and deemed cost of capital for small utilities without third-party debt;

F. By Order G-50-12 dated April 19, 2012, the Commission, among other matters, set out the further procedural matters to be addressed in the proceeding and a Preliminary Minimum Filing Requirements (MFR) for Affected Utilities document. Parties were invited to make submissions on the Preliminary MFR for Affected Utilities by May 3, 2012, and on the allocation of Participant Assistance/Cost Awards (PACA), PACA eligibility, and/or the Draft Preliminary Regulatory Timetable by May 9, 2012;

G. By Order G-72-12 dated June 1, 2012, the Commission, among other matters, issued the Final Minimum Filing Requirements for Affected Utilities and the Preliminary Regulatory Timetable for the proceeding;

H. On June 8, 2012, the Commission released "A Survey of Cost of Capital Practices in Canada" prepared by The Brattle Group for the Commission (Brattle Report). Utilities and Interveners were provided with the opportunity to ask Information Requests on the Brattle Report;

I. By Order G-84-12 dated June 20, 2012, the Commission amended the Preliminary Regulatory Timetable, establishing, among other things, a Procedural Conference for October 2, 2012 and the commencement date for an oral hearing, if required, on December 12, 2012. The Procedural Conference was subsequently rescheduled to October 4, 2012;

J. At the Procedural Conference the Commission received, among others, submissions on the following items: (1) the appropriate benchmark utility for the determination of the generic cost of capital; (2) whether a Stage 2 for the purpose of determining an appropriate cost of capital for Affected and Other Utilities to immediately follow Stage 1 was desirable; (3) whether an oral phase was required and (4) the proposed timetable going forward;

K. By Order G-148-12 dated October 11, 2012, the Commission determined that : (1) FEI in its present pre-amalgamation state, would serve as the benchmark for the proceeding and whether FEI in 2012 is a pure play gas distribution utility would be determined following the hearing of further evidence; (2) a Stage 2 would be added to the proceeding with the schedule to be determined prior to the end of Stage 1; and (3) the review of the proceeding would continue by way of an oral hearing commencing on December 12, 2012;

L. By Order G-187-12 dated December 10, 2012, the Commission ordered that: (1) the current ROE and capital structure for FEI, the designated benchmark utility, and all regulated entities in B.C. that rely on the benchmark utility, except British Columbia Hydro and Power Authority, are to be maintained and made interim, effective January 1, 2013; and (2) any determinations of the premiums on the benchmark ROE and capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decision in Stage 2; M. The oral public hearing took place over a period of seven days between December 12, 2012 and December 21, 2012. A total of eight witness panels from FBCU and Interveners gave evidence;

N. FBCU, PNG, Corix, AMPC/CEC, ICG and BCPSO filed Final Submissions. FBCU filed a Reply Submission; and

O. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-75-13

NOW THEREFORE, the Commission orders as follows:

1. The common equity component appropriate for the benchmark utility, FEI, effective January 1, 2013 is 38.5 percent.

2. A Return on Equity (ROE) for the benchmark utility, FEI, is established at 8.75 percent effective January 1, 2013.

3. An Automatic Adjustment Mechanism (AAM) formula for annually setting the ROE of the benchmark utility between ROE proceedings is adopted commencing January 1, 2014. The AAM formula will operate until December 31, 2015. The implementation of the model will be subject to conditions outlined in the Decision.

4. FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015.

5. The common equity component and the ROE approved in Paragraphs 1 and 2 of this Order will continue to serve as the Benchmark cost of capital for any other utility in British Columbia that uses a Benchmark Utility to set rates.

6. Within 30 days of the date of this Order, FEI is to file:

   (a) a document setting out how and when it will implement the change to its capital structure;

   (b) amended rate schedules in accordance with paragraphs 1 and 2 of this Order as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013.

7. Small utilities without third-party debt are to include a deemed component of short-term debt of 4 percent.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-1	G-20-12 (Feb 28, 2012)	• Stated purpose in establishing the GCOC proceeding • All regulated utilities determined to be applicants in this proceeding. Utilities are divided into "Affected Utilities" and "Other Utilities." • Issued initial regulatory timetable for registration of Utilities and Interveners and written submissions on the Preliminary Scoping Document
A-3	G-47-12 (April 18, 2012)	• Issued Final Scoping Document
A-5	G-50-12 (April 19, 2012)	• Issued preliminary Minimum Filing Requirements (MFR) • Issued preliminary regulatory timetable for written submissions on the MFR and the cost allocation of Participant Assistance/Cost Awards (PACA) and PACA eligibility
A-6	G-72-12 (June 1, 2012)	• Issued Final MFR • Determined the principles in the allocation of PACA costs and PACA cost eligibility • Considered expansion of the current proceeding by conducting the GCOC proceeding in two stages • Issued preliminary regulatory timetable for a Procedural Conference and Stage 1 of the GCOC proceeding. • Put on the record the terms of reference for the survey Report carried out by The Brattle Group
A-9	Order G-84-12 (June 20, 2012)	• Issued amended preliminary regulatory timetable

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-16 and A-17	Letter L-52-12 (September 13, 2012)	• Established the amended date and agenda for the Procedural Conference
A-22	G-148-12 (October 11, 2012)	• Determined that FEI in 2012 in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding • Determined that a Stage 2 will be added to the proceeding • Determined that review will take place by an oral hearing commencing on December 12, 2012
A-30	G-187-12 (December 10, 2012)	• Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013

LIST OF APPEARANCES

G. Fulton, Q.C.	Commission Counsel
L. Bussoli	Commission Counsel
M. Ghikas	FortisBC Utilities
T. Ahmed	FortisBC Utilities
M. Cheesman	Corix Multi-Utility Services Inc. (Corix)
J. Kennedy	Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
R.B. Wallace, Q.C.	Association of Major Power Customers of B.C. (AMPC)
R. Hobbs	Industrial Customers Group of FortisBC Inc. (ICG)
L. Worth	British Columbia Pensioners' and Seniors' Organization (BCPSO)
E. Kung	British Columbia Pensioners' and Seniors' Organization (BCPSO)
T. Braithwaite	British Columbia Pensioners' and Seniors' Organization (BCPSO)
C. Weafer	Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Commercial Energy Consumers of British Columbia (CEC)
J. Christian	British Columbia Hydro and Power Authority (BC Hydro)
B. Hobkirk	British Columbia Hydro and Power Authority (BC Hydro)
R. Hanson	River District Energy
J. Quail	Canadian Office and Professional employees' Union Local 378

E. Cheng Y. Domingo J. Tran B. Grant J. Fraser	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF PANELS

FORTISBC INC., FORTISBC ENERGY INC., FORTISBC ENERGY (VANCOUVER ISLAND) INC., AND FORTISBC ENERGY (WHISTLER) INC.

PANEL 1 - COMPANY EVIDENCE

Roger A. Dall'Antonia	Vice President, Strategic Planning, Corporate Development and Regulatory Affairs (Panel Chair)
Douglas Stout	Vice President, Energy Solutions and External Relations
Cynthia Des Brisay	Vice President, Energy Supply and Resource Development
Michele Leeners	Vice President, Finance and CFO

PANEL 2 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

Kathleen C. McShane, MBA, CFA	President Foster Associates, Inc.

PANEL 3 - EXPERT OPINION ON AUTOMATIC ADJUSTMENT MECHANISMS

James M. Coyne	Concentric Advisors

PANEL 4 - EXPERT OPINION ON CAPITAL MARKETS

Aaron M. Engen	Managing Director BMO Capital Markets (Energy Infrastructure Group)

PANEL 5 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

James H. Vander Weide, PhD	Duke University

CORIX MULTI-UTILITY SERVICES INC. (CORIX)

Pauline M. Ahern, MBA	Principal AUS Consultants

LIST OF PANELS

THE INDUSTRIAL CUSTOMERS GROUP OF FORTISBC INC. (ICG)

Andrew Safir, PhD	President Recon Research Corporation

THE ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC), THE COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC), THE BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO), COLLECTIVELY THE BC UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 1

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated February 28, 2012 and Order G-20-12 – Establishing an initial Regulatory Timetable
A-2	Letter Dated April 17, 2012 – Response clarifying Union Gas's Intervener Status
A-3	Letter dated April 18, 2012 and Order G-47-2012 – Reasons for Decision and Final Scoping Document
A-4	Letter dated April 18, 2012 – Appointment of Panel
A-5	Letter dated April 19, 2012 - Order G-50-12 List of Further Procedural Matters
A-6	Letter dated June 1, 2012 - Order G-72-12 Issuing Preliminary Timetable, PACA costs, Final Minimum Filing Requirements for Affected Utilities
A-7	Letter dated June 6, 2012 - Request for Variance of Regulatory Timetable Order G-72-12
A-8	Letter dated June 8, 2012 – Commission Consultant's Survey Report
A-9	Letter dated June 20, 2012 – Order G-84-12 - Amended Preliminary Regulatory Timetable
A-10	Letter dated July 27, 2012 – Request for Comments on the Addition of a Panel Member
A-11	Letter dated August 22, 2012 – Appointment of Commissioner Mr. R. Giammarino
A-12	Letter dated August 31, 2012 – Information Request No. 1 to FortisBC Utilities
A-13	**CONFIDENTIAL** Letter dated August 31, 2012 – CONFIDENTIAL Information Request No. 1 to FortisBC Utilities
A-14	Letter dated August 31, 2012 – Information Request No. 1 to PNG

Exhibit No.	Description
A-15	Letter dated August 31, 2012 – Information Request No. 1 to Corix
A-16	Letter dated September 13, 2012 – L-52-12 Amending Regulatory Timetable
A-17	Letter dated September 27, 2012 – Agenda for Procedural Conference
A-18	Letter dated October 9, 2012 – Information Request No. 2 to FortisBC Utilities
A-19	**CONFIDENTIAL** Letter dated October 9, 2012 – CONFIDENTIAL Information Request No. 2 to FortisBC Utilities
A-20	Letter dated October 9, 2012 –Information Request No. 2 to Corix
A-21	Letter dated October 11, 2012 – Order G-148-12 and Reasons for Decision
A-22	Letter dated October 24, 2012 - Request to Access Confidential Material
A-23	Letter dated October 31, 2012 - Access to Confidential Material Response
A-24	Letter dated November 1, 2012 – Confidential Material Access to AMPC (Exhibit C6-11)
A-25	Letter dated November 16, 2012– Information Request No. 1 to ICG on Intervener Evidence
A-26	Letter dated November 16, 2012– Information Request No. 1 to AMPC on Intervener Evidence
A-27	Letter dated November 20, 2012 – Request for submissions
A-28	Letter dated December 3, 2012 – Oral Public Hearing Information
A-29	Letter dated December 5, 2012 – Opening Statements Clarification
A-30	Letter dated December 10, 2012 - Commission Order G-187-12 establishing the current ROE and capital structure
A-31	Letter dated February 14, 2013 – Commission Response to request for extension

Exhibit No.	Description
COMMISSION STAFF DOCUMENTS	
A2-1	Letter Dated February 28, 2012 - Commission Staff Filing British Columbia Utilities Commission letter dated November 28, 2011-Preliminary Notification of Initiation of Generic Cost of Capital Proceeding
A2-2	Letter Dated February 28, 2012 - Commission Staff Filing the Terasen Utilities (December 8, 2010) – Automatic Adjustment Mechanism Review
A2-3	Letter dated June 8, 2012 – Commission Staff Filing the Brattle Group Survey of Cost of Capital Practices in Canada
A2-4	Letter dated July 12, 2012 - Commission Staff Filing Response to AMPC Information Request to Commission Consultants
A2-5	Letter dated July 12, 2012 - Commission Staff Filing Response to FEU Information Request on the Consultants Survey Report
A2-6	Letter dated July 12, 2012 - Commission Staff Filing Response to Industrial Customer Group Information Request on the Consultants Survey Report
A2-7	Letter dated July 12, 2012 - Commission Staff Filing Response to BCOAPO Information Request to Consultants Report
A2-8	Letter dated July 12, 2012 - Commission Staff Filing Response to CEC Information Request to Consultants Report
A2-9	Letter dated July 13, 2012 – Commission Staff Filing BCUC Request for Proposal for a Survey of Canadian Cost of Capital Practice Report
A2-10	Letter dated August 31 2012 – Commission Staff Filing Behavior of the Firm under Regulatory Constraint by Harvey Averch and Leland L. Johnson
A2-11	Letter dated August 31 2012 – Commission Staff Filing Extract from Terasen 2005 and 209 ROE CAP Applications
A2-12	Letter dated August 31 2012 – Commission Staff Filing Extract from FEU 2012-13 Revenue Requirements Decision
A2-13	Letter dated August 31 2012 – Commission Staff Filing Extract from Bloomberg News (Report dated August 6, 2012)

Exhibit No.	Description
A2-14	Letter dated August 31 2012 – Commission Staff Filing Capital Structure - A Comparison
A2-15	Letter dated August 31 2012 – Commission Staff Filing Summaries of Reports and Notes from Recent Credit Rating Agencies and Investment Banks on FEI's Risk and Credit Metrics
A2-16	Letter dated August 31 2012 – Commission Staff Filing Extract from Washington Utilities and Transportation Commission Order 08 Decision
A2-17	Letter dated August 31 2012 – Commission Staff Filing Fitch Affirms National Fuel Gas' IDR at 'A'
A2-18	Letter dated August 31 2012 – Commission Staff Filing The City of Vancouver - District Energy Connectivity Standards Information for Developers
A2-19	Letter dated August 31 2012 – Commission Staff Filing City of Surrey – District Energy System By-law, 2012, No. 17667
A2-20	Letter dated August 31 2012 – Commission Staff Filing Extract from BCUC Information Request No. 2 to River District Energy Limited Partnership
A2-21	Letter dated August 31 2012 – Commission Staff Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities December 11, 2009
A2-22	Letter dated August 31 2012 – Commission Staff Filing Ontario Energy Board Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012
A2-23	Letter dated August 31 2012 – Commission Staff Filing Summary of Reports from Recent Credit Rating Agencies and Investment Banks on PNG's Risks and Credit Metrics
A2-24	Letter dated October 9, 2012 – Commission Staff Filing Bradshaw et al. - Playing Favorites
A2-25	Letter dated October 9, 2012 – Commission Staff Filing CTA-Risk-Free Rate Determination
A2-26	Letter dated October 9, 2012 – Commission Staff Filing Exhibit A2-26 OEB Cost of Capital Parameter, May 1 2012

Exhibit No.	Description
A2-27	Letter dated November 16, 2012 - Commission Staff Filing Cost of Capital by Sector_NYU_Value Line Database
A2-28	Letter dated November 16, 2012 - Commission Staff Filing Gau, Thompson 2012 Capitalization Rate Study
A2-29	Letter dated November 16, 2012 - Commission Staff Filing Schaeffler and Weber- The Cost of Equity of Network Operators
A2-30	Letter dated November 16, 2012 - Commission Staff Filing TD-Long-Term Returns October 2012
A2-31	Letter dated November 16, 2012 - Commission Staff Filing Ashton et al- Analysts' Optimism in Earnings Forecasts
A2-32	Letter dated November 16, 2012 - Commission Staff Filing Understanding Corporate Bond Spreads Using Credit Default Swaps
A2-33	Submitted at Oral Hearing December 12, 2012 – Commission Staff Filing FEU 2012-2013 Revenue Requirements G-44-12 Compliance Filing
A2-33-1	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing page 1 of letter dated may 1, 2012 to BCUC from FortisBC, with two pages attached
A2-34	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Vancouver Sun Article Natural gas seen as green fuel
A2-35	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Staff Witness Aid
A2-36	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing pages 7 to 10 from Standard & Poors Report
A2-37	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Long-Term Economic Forecast, TD Economics, September 18, 2012
A2-38	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Attachment 8.2(A), page 17 of 18, Results of Differences in Systematic Risk
A2-39	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Extract from Order No. 09-176 from Public Utility Commission of Oregon

Exhibit No.	Description
A2-40	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Rating Report, February 29, 2012 from DBRS
A2-41	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Document Headed Moody's Investors Service, Credit Opinion: FortisBC Energy Inc.
A2-42	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Five-Page Document, First Page Headed Returns on Average Common Stock Equity for Sample of U.S. Utilities
A2-43	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Approaches to Estimating the Deemed Interest Rate for Long Term Debt
A2-44	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Excerpt of FEI Kelowna DES CPCN Application
A2-45	Submitted at Oral Hearing December 17, 2012 – Document Headed Credit Rating and Equity Risk Premium
A2-46	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Weathering the Headwinds to Canada's Economic Growth 21 November 2012
A2-47	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Puget Sound Energy Inc.
A2-48	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Power & Utilities Research, the One-Two Punch: Growth Combined with Attractive Yield
A2-48-1	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Extract from BMO Capital Markets, page 11, Headed Power & Utilities
A2-49	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Ontario Energy Board, Report of Board, December 20, 2006
A2-50	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First
A2-51	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Witness Aid Prepared by Commission Staff Entitled Informed Expert Judgment

Exhibit No.	Description

AFFECTED UTILITIES DOCUMENTS

B1-1	**BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU)** Letter Dated March 15, 2012 – Notice of Registration
B1-2	Letter Dated March 21, 2012 – FBCU Submission on the Preliminary Scoping Document
B1-3	Letter Dated May 3, 2012 – FBCU Submission on Minimum Filing Requirements
B1-4	Letter Dated May 9, 2012 – FBCU Submission regarding Order G-50-12 Appendix A
B1-5	Letter Dated June 5, 2012 – FBCU Submitting Request for Variance of Preliminary Regulatory Timetable
B1-6	Letter Dated June 5, 2012 – FBCU Reply Submissions regarding Request for Variance of Preliminary Regulatory Timetable
B1-7	Letter Dated June 22, 2012 – FBCU Submitting Information Request regarding the Commission Consultant Survey Report
B1-8	Letter Dated August 2, 2012 – FBCU Submitting comments regarding the addition of a panel member
B1-9	Letter Dated August 3, 2012 – FBCU Submitting Evidence
B1-9-1	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 1 to 2
B1-9-2	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3A – Debt Investment Analyst Reports for FEI
B1-9-3	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Beacon to Credit Suisse
B1-9-4	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Macquarie to UBS

Exhibit No.	Description
B1-9-5	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 4 to 11
B1-9-6	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendices B to J
B1-9-7	**CONFIDENTIAL** Letter Dated August 3, 2012 – FBCU Submitting Evidence CONFIDENTIAL Appendices
B1-10	Letter Dated September 24, 2012 – FBCU Submitting Response to BCPSO IR No. 1
B1-11	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – FBCU
B1-12	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – A. Engen
B1-13	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Concentric
B1-14	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Dr. Vander Weide
B1-15	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – K. McShane
B1-16	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – A. Engen
B1-17	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Concentric
B1-18	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Dr. Vander Weide
B1-19	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – K. McShane
B1-20	Letter Dated September 24, 2012 – FBCU Response to BCUC IR No.1
B1-20-1	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Confidential Response to BCUC IR No.1
B1-21	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Response to Confidential BCUC IR No.1

Exhibit No.	Description
B1-22	Submitted at Procedural Conference Letter Dated October 3, 2012 – FBCU Counsel's Oral Submissions
B1-23	Letter dated October 26, 2012 – FBCU Response to Confidentiality Request
B1-24	Letter dated October 29, 2012 – FBCU Response to BCUC IR No. 2
B1-25	**CONFIDENTIAL** Letter dated October 29, 2012 – FBCU Response to BCUC Confidential IR No. 2
B1-26	Letter dated October 29, 2012 – FBCU Response to BCPSO IR No. 2
B1-27	Letter dated November 2, 2012 – FBCU Comments regarding Confidential Material Access
B1-28	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to AMPC/BC Utility Customers on the Evidence of Dr. Booth
B1-29	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to ICG on the Evidence of Dr. Safir
B1-30	Letter Dated November 23, 2012 – FBCU Submission on Interim Rates Jan 1, 2013
B1-31	Letter Dated November 30, 2012 – FBCU Submitting Witness Panels and Direct Testimony
B1-32	Letter dated December 6, 2012 – FBCU Submitting Rebuttal Evidence
B1-33	Letter dated December 10, 2012 – FBCU Submitting Opening Statement
B1-34	Submitted at Oral Hearing December 12, 2012 – FBCU Written Opening Statement of Counsel
B1-35	Submitted at Oral Hearing December 12, 2012 – FBCU Revised: Exhibit B1-9-6, Appendix H, page 51, Figure 34
B1-36	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 1
B1-37	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 2
B1-38	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 3

Exhibit No.	Description
B1-39	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 4
B1-40	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 5
B1-41	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 6
B1-42	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 7
B1-43	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 8
B1-44	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 9
B1-45	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 10
B1-46	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 11
B1-47	Submitted at Oral Hearing December 14, 2012 – FBCU Filing Testimony of Kathleen C. McShane Tab 2
B1-48	Submitted at Oral Hearing December 17, 2012 – FBCU Undertaking No. 12
B1-49	Submitted at Oral Hearing December 18, 2012 – FBCU Filing Testimony Figures Update
B1-49-1	Letter received January 3, 2013 – FBCU Filing Remaining Chart Updates
B1-50	Submitted at Oral Hearing December 19, 2012 – FBCU Filing 104 page Collection of Documents Used in Cross Examination of Dr. Booth
B1-51	Submitted at Oral Hearing December 21, 2012 – FBCU Filing Compendium of Extracts, First Page Entitled Fair Return for Terasen Gas Inc. (TGI) August 2009
B1-52	Letter received January 3, 2013 – FBCU Undertaking No. 13
B1-53	Letter received January 3, 2013 – FBCU Undertaking No. 14
B1-54	Letter received January 3, 2013 – FBCU Undertaking No. 15
B1-55	Letter received January 3, 2013 – FBCU Undertaking No. 16
B1-56	Letter received January 3, 2013 – FBCU Undertaking No. 17
B1-57	Letter received January 3, 2013 – FBCU Undertaking No. 18

Exhibit No.	Description
B1-58	Letter received January 3, 2013 – FBCU Undertaking No. 19
B1-59	Letter received January 3, 2013 – FBCU Undertaking No. 20
B1-60	Letter received January 29, 2013 – FBCU Undertaking No. 21
B1-61	Letter received January 29, 2013 – FBCU Undertaking No. 22
B1-62	Letter received January 29, 2013 – FBCU Undertaking No. 23
B1-63	Letter received January 29, 2013 – FBCU Undertaking No. 24
B1-64	Letter received January 29, 2013 – FBCU Undertaking No. 25
B1-65	Letter received January 29, 2013 – FBCU Undertaking No. 26
B1-66	Letter received January 29, 2013 – FBCU Undertaking No. 27
B1-67	Letter received January 29, 2013 – FBCU Undertaking No. 28
B1-68	Letter received January 29, 2013 – FBCU Undertaking No. 29
B2-1	**CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated March 14, 2012 – Notice of Registration
B2-2	Letter Dated March 21, 2012 – Corix Submission on the Preliminary Scoping Document
B2-3	Letter Dated May 3, 2012 – Corix Submission on Minimum Filing Requirements
B2-4	Letter Dated May 9, 2012 – Corix Submission regarding Order G-50-12 Appendix A
B2-5	Letter Dated June 8, 2012 – Corix Submission on FBCU Request for Variance
B2-6	Letter Dated August 3, 2012 – Corix Submitting Comments Regarding the Addition of a Panel Member
B2-7	Letter Dated August 3, 2012 – Corix Submitting Evidence
B2-8	Letter Dated September 24, 2012 – Corix Submitting Response to BCPSO IR No. 1
B2-9	Letter Dated September 24, 2012 – Corix Submitting Response to BCUC IR No. 1

Exhibit No.	Description
B2-10	Letter Dated October 18, 2012 – Corix Submitting Response to BCUC IR No. 2
B2-11	Letter Dated November 23, 2012 – Corix Submission regarding A-27
B2-12	Submitted at Oral Hearing December 18, 2012 – Corix Filing Opening Remarks of Counsel for Corix Multi-Utility Services Inc., December 12, 2012
B2-13	Submitted December 24, 2012 – Corix Filing Undertaking Document Titled Before the Florida Public Service Commission
B2-14	Submitted December 24, 2012 – Corix Filing Undertaking Document titled Comparison of Business Risk Adjustments in Cost of Capital Testimony Filed by Ms. Pauline M. Ahern
B2-15	Letter received January 3, 2013 - Corix Filing Response to Undertaking
B3-1	**PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG)** Online Registration Dated March 16, 2012 – Notice of Registration
B3-2	Letter Dated March 21, 2012 – PNG Submission on the Preliminary Scoping Document
B3-3	Letter Dated May 3, 2012 – PNG Submission on Minimum Filing Requirements
B3-4	Letter Dated May 9, 2012 – PNG Submission Regarding Order G-50-12 Appendix A
B3-5	Letter Dated June 8, 2012 – PNG Submission Regarding Variance of the Regulatory Timetable
B3-6	Letter Dated August 3, 2012 – PNG Submitting Comments Regarding the Addition of a Panel Member
B3-7	Letter Dated August 3, 2012 – PNG Submitting Evidence
B3-8	Letter Dated September 24, 2012 – PNG Submitting Response to BCUC IR No. 1
B3-9	Letter Dated September 24, 2012 – PNG Submitting Response to BCPSO
B3-10	Letter Dated September 24, 2012 – PNG Submitting Response to AMPC, BCPSO and CEC
B3-11	Letter Dated November 23, 2012 – PNG Submission Regarding A-27

Exhibit No.	Description
B3-12	Letter Dated November 30, 2012 – PNG Submitting Comments regarding Witness Panels
	OTHER UTILITIES DOCUMENTS
B4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter Dated March 12, 2012 – Notice of Registration
B4-2	Letter Dated March 21, 2012 – BCH Submission on the Preliminary Scoping Document
B4-3	Letter Dated May 3, 2012 – BCH Submission on Minimum Filing Requirements
B4-4	Letter Dated May 9, 2012 – BCH Submission Regarding Order G-50-12 Appendix A
B4-5	Letter Dated June 8, 2012 – BCH Submission Regarding variance of the Regulatory Timetable
B4-6	Letter Dated August 3, 2012 – BCH Submitting Comments Regarding the Addition of a Panel Member
B4-7	Letter Dated November 23, 2012 - BCH Submission Regarding A-27
B4-8	Letter Dated November 30, 2012 – BCH Submitting Comments Regarding Witness Panels
B5-1	**RIVER DISTRICT ENERGY (RDE)** Letter Dated March 12, 2012 – Notice of Registration
	INTERVENER DOCUMENTS
C1-1	**UNION GAS LIMITED (UG)** Letter dated March 5, 2012 – Request for Intervener Status by Patrick McMahon
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated March 15, 2012 – Request for Intervener Status by James Quail
C2-1-1	Letter dated March 20, 2012 – COPE 378 Submitting Intervention Supplementary Comments
C2-2	Letter dated April 19, 2012 - COPE 378 Submitting Updating Consultant details
C2-3	Letter dated June 26, 2012 - COPE 378 Submitting Updating Consultant Information

Exhibit No.	Description
C3-1	**SENTINEL ENERGY MANAGEMENT (SEM)** Online Registration dated March 20, 2012 – Request for Intervener Status by Jim Langley
C4-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated March 20, 2012 Via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C4-2	Letter Dated March 21, 2012 – ICG Submission on the Preliminary Scoping Document
C4-3	Letter Dated May 3, 2012 – ICG Submission regarding the Preliminary Minimum Filing Requirements for Affected Utilities
C4-4	Letter Dated May 9, 2012 – ICG Submission Regarding Order G-50-12 Appendix A
C4-5	Letter Dated June 8, 2012 – ICG Submission regarding Variance of the Regulatory Timetable
C4-6	Letter Dated June 21, 2012 – ICG Submitting Information Request Regarding the Commission Consultant Survey Report
C4-7	Letter Dated August 31, 2012 – ICG Submitting Information Request No. 1
C4-8	Letter Dated October 24, 2012 - ICG Submitting Comments regarding Request for Confidential Information
C4-9	Letter dated November 5, 2012 – ICG Submitting Evidence
C4-10	Letter dated November 6, 2012 – ICG Submitting Confidential Undertakings
C4-11	Letter dated November 30, 2012 – ICG Submitting Responses to Information Request No. 1
C4-12	Letter dated November 30, 2012 – ICG Submission Regarding Exhibit A-27
C4-13	Submitted at Oral Hearing December 12, 2012 – ICG Opening Comments
C4-14	Submitted at Oral Hearing December 14, 2012 – ICG Filing Tab 2 Testimony of Kathleen C. McShane
C4-15	Submitted at Oral Hearing December 17, 2012 – ICG Filing Opening Statement of Dr. Andrew Safir

Exhibit No.	Description
C4-16	Letter dated January 14, 2013 – ICG Submitting Undertakings
C4-17	Letter dated January 25, 2013 – ICG Submitting Dr. Lawrence Booth Undertaking No. 2
C5-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** (previously BC Old Age Pensioner' Organization *et. al*.) **VIA EMAIL -** Letter Dated March 20, 2012 – Request for Intervener Status by Leigha Worth, Tannis Braithwaite and Bill Harper
C5-2	Letter Dated March 21, 2012 – BCOAPO Submission on the Preliminary Scoping Document
C5-3	Letter Dated May 3, 2012 – BCOAPO Submission on Minimum Filing Requirements
C5-4	Letter Dated May 9, 2012 – BCOAPO Submission Regarding Order G-50-12 Appendix A
C5-5	Letter Dated June 8, 2012 – BCOAPO Submission Regarding Variance of the Regulatory Timetable
C5-6	Letter Dated June 22, 2012 – BCOAPO Submitting Information Request Regarding the Commission Consultant Survey Report
C5-7	Letter dated July 23, 2012 – BCOAPO Submitting Notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C5-8	Letter Dated August 3, 2012 – BCPSO Submitting Comments Regarding the Addition of a Panel Member
C5-9	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to Corix
C5-10	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to FBCU
C5-11	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to PNG
C5-12	Letter Dated October 9, 2012 - BCPSO Submitting Information Request No. 2 to FBCU

Exhibit No.	Description
C5-13	Letter Dated October 9, 2012 - BCPSO Submitting Contact Update
C5-14	Letter Dated November 30, 2012 - BCPSO Submission Regarding Exhibit A-27
C5-15	Submitted at Oral Hearing December 17, 2012 – BCPSO Filing Business Spectator Document
C6-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated March 20, 2012 – Request for Intervener Status by Richard Stout and Lloyd Guenther
C6-2	Letter Dated May 2, 2012 – AMPC Submitting Contact Update
C6-3	Letter Dated May 3, 2012 – AMPC Submission on Minimum Filing Requirements
C6-4	Letter Dated May 9, 2012 – AMPC Submission Regarding Order G-50-12 Appendix A
C6-5	Letter Dated June 8, 2012 – AMPC Submission Regarding Variance of the Regulatory Timetable
C6-6	Letter Dated June 22, 2012 – AMPC Submitting Information Request Regarding the Commission Consultant Survey Report
C6-7	Letter Dated August 3, 2012 – AMPC Submitting Comments Regarding the Addition of a Panel Member
C6-8	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU
C6-9	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-9-1	Letter Dated September 23, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Corrected Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-10	Letter Dated October 22, 2012 - AMPC Filing a Request for Confidential Information
C6-11	Letter Dated October 31, 2012 - AMPC Submitting Comments regarding Access to Confidential Information
C6-12	Letter dated November 5, 2012 – AMPC Submitting Evidence

Exhibit No.	Description
C6-13	Letter dated November 5, 2012 – AMPC Submitting Confidential Undertakings
C6-14	Letter dated November 30, 2012 – AMPC Submission regarding Exhibit A-27
C6-15	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to BCUC
C6-16	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to FBCU
C6-17	Submitted at Oral Hearing December 12, 2012 – AMPC Filing BC Natural Gas Strategy Fueling BC's Economy for the Next Decade and Beyond
C6-18	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 17d
C6-19	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 21 i
C6-20	Submitted at Oral Hearing December 17, 2012 – AMPC filing Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding Direct Testimony of James M. Coyne
C6-21	Submitted at Oral Hearing December 18, 2012 – AMPC Filing Witness Aid Prepared by BC Utilities Customers
C6-22	Submitted at Oral Hearing December 19, 2012 – AMPC filing Dr. Booth's Opening Statement
C6-23	Letter dated January 18, 2013 – AMPC Submitting Dr. Booth Undertaking No. 1
C6-24	Letter Dated February 14, 2013 – AMPC Submitting Extension Request
C7-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter Dated March 20, 2012 – Request for Intervener Status by Christopher Weafer
C7-2	Letter Dated May 9, 2012 – CEC Submission Regarding Order G-50-12 Appendix A
C7-3	Letter Dated June 8, 2012 – CEC Submission Regarding variance of the Regulatory Timetable

Exhibit No.	Description
C7-4	Letter dated June 25, 2012 – CEC Submitting Information Request Regarding the Commission Consultant Survey Report
C7-5	Letter Dated August 3, 2012 – CEC Submitting Comments Regarding the Addition of a Panel Member
C7-6	Letter dated November 9, 2012 – CEC Submitting Confidential Undertakings

INTERESTED PARTY DOCUMENTS

D-1	**AT BUSINESS CONSULTING (ATB)** Online Registration dated May 9, 2012 – Request for Interested Party Status by Anastasios Tsalamandris

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
	Capital structure (debt/equity ratio)	60/40 (actual)	60/40 (actual)	60/40 (actual; proposed)		60/40 (actual)	Deemed 60/40	Deemed 60/40	Deemed 60/40
	Equity Risk Premium	N/A	0 bps (approved)	50 bps (proposed)		50 bps (approved)	50 bps (approved)	100 bps (approved)	50 bps (approved)
1	Technology risk/system performance risk associated with chosen technologies	Natural Gas: proven technology	Geo-exchange loop field system and heat recovery with high efficiency natural gas boilers equipment	Recovered waste heat from TELUS Data Centre with peaking and redundant backup heat supplied by Centre Heat Distribution Ltd.: low risk	Slightly higher for PCI / TG than FEI NG	High efficiency condensing boilers: proven technology; Ground source heat pumps; less established technology	Natural gas boilers proven technology	Biomass Gasification innovative technology; Natural Gas boilers; proven technology (while DGE not yet on biomass, the Commission approved the technology)	Natural Gas: boiler: proven technology

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
2	Fuel Risk cost and availability	Natural gas: Low-medium	Low risk: free energy from ground and heat recovery, but cost risk for electricity used to operate heat pumps and TES equipment, and for natural gas for supplementary heat and peaking	Data Centre that supplies waste heat is assumed to be available throughout the 20 year term of the analysis: low risk Data Centre ceases operation	Lower for PCI / TG than FEI NG	Natural gas and electricity: Low-medium; Heat from ground: low (some energy cost risk in electricity costs to operate GSHPs)	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant	Biomass: medium-high; natural gas; low-medium	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant
3	Customer Base (e.g., diversity, certainty, growing, declining)	Established and diverse customer base but very slow growth	Greenfield utility four types of customers	Not large customer base or significant diversity: low risk	Higher for PCI / TG than FEI NG (NG has much greater diversity)	Established customer: low risk	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out
4	Default risk of customer	Minimal	Minimal	Minimal	Similar for PCI / TG as for FEI NG	Minimal as SD has budget constraints as well	Minimal	Minimal	Minimal

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ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
5	Property development risk	Medium to high: there are competing energy options	Low risk: all customers bound by agreement	Majority of tenants committed but customers can still leave: low risk	Lower for PCI / TG than FEI NG	None, as not a new development	Low: phased approach to capital deployment	High: build first approach to capital deployment	Low: phased approach to capital deployment
6	Developer / customer connection risk	Medium to high: due to building stock changes and competitive energy sources	Low Risk: customers will connect on occupancy	Low Risk: customers will connect on occupancy	Lower for PCI / TG than FEI NG	Low, as one known customer with existing sites	Low: mandatory connection	Low: mandatory connection	Low: mandatory connection
7	Load Forecast Uncertainty	Minimal in the short term, as mature utility with deferral account; somewhat higher in the long term	Inherent uncertainty in load forecast	FAES proposes to take forecast risk on actual energy throughput versus forecast for 5 year period: Low-medium	Higher for PCI / TG than FEI NG	Low, as established energy load	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
8	Utility size	Large and mature utility	Project is carried out by a separate corporate entity, Small development specific utility.	Project is carried out by separate corporate entity, Small development specific utility.	Higher for PCI / TG than FEI NG	Project is carried out by separate corporate entity	Small development specific utility	Small development specific utility	Small development specific utility
9	Initial construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
10	Future Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
11	Operating cost risk	Minimal as revenue requirement application to recover costs	Minimal as mechanism in place to recover costs	Low-medium risk: as deferral accounts do not cover all O&M variances between forecast and actual	Higher for TG, similar for PCI relative to FEI NG	Minimal as mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
12	Public Acceptance Risk	Medium as natural gas is an established and widely used technology but public perceives it as less than clean	Low as seen as green alternative	Low	Lower for PCI / TG than FEI NG	Low as seen as green alternative	Low as seen as a green alternative	Low as gasification technology part of approval process for the development and already selected at the time of the CPCN application	low as seen as a green alternative
13	Fixed/Variable rate design	15% fixed/85% variable	~~100% variable~~ Rate Design Not Approved	100% variable (volume rate)	Higher for TG, relative to FEI NG PCI Rate Design not Approved	100% variable	60% fixed/40% variable	50% fixed/50% variable	66% fixed / 34% variable

ORDER C-1-13
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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
14	Levelized approach to rates	No	~~Only in first three years then transition to cost of service~~ Rate Design not Approved	The rates charged for the first five years have been mutually agreed upon using a benchmark based on BC Hydro RIB Step 1 and Step 2	Slightly higher for TG, relative to FEI NG PCI Rate Design Not Approved	No, transitional market rate and deferral account	Yes	Yes	Yes
15	Financial risk	Low-medium: appropriate standalone financing structure for capital markets	Medium (similar to DSD)	Forecast risk and rates fixed for first five years (other than one-time adjustment for GCOC changes) impacts financial risk: medium risk justifies 50 bps on FEI utility benchmark	Higher for PCI / TG than FEI NG	Medium	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
16	Competitive challenges	Competitive with electricity and competition from alternative energy providers	Other TES providers and electricity	Other TES providers and electricity	Lower for PCI / TG than FEI NG	Other TES providers and electricity	Other utilities and electricity	Other utilities and electricity	Other utilities and electricity
17	Provincial climate change and energy policies	Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use.	Favourable government policies	Favourable government policies	Lower for PCI / TG than FEI NG	Favorable govt. policies	Favourable govt. policies	Favourable govt. policies	Favourable govt. policies
18	Regulatory uncertainty	Low to medium: uncertainty exists for service offerings within the natural gas class of service.	Medium risk: New, uncertainty, scrutiny and not streamlined Rate Design Denied as Applied	Medium risk: New, uncertainty, scrutiny and not streamlined	Higher for PCI / TG than FEI NG	Medium risk: new, uncertainty, scrutiny and not streamlined	Medium risk: New, uncertainty, scrutiny, alternative energy centre not yet approved	Medium risk: New, uncertainty, scrutiny	Medium risk: New, uncertainty, scrutiny

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
19	Business Development Risk	Minimal	Low – deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1.) [Shareholder ultimately at risk for the TESDA]	FAES has agreed to purchase the TGTES from the Partnership upon commissioning for actual construction cost of $7.9 million up to a maximum of 30% above the $7.9 million estimate.	Higher for PCI / TG than FEI NG	Low: deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) (Shareholder ultimately at risk for the TESDA)	High as part of overhead cots	High as part of overhead cots	High as part of overhead cots

COST OF CAPITAL ESTIMATION MODELS AND KEY INPUTS

DISCOUNTED CASH FLOW MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
McShane	Constant Growth	12 US utilities	4.9% - Average of consensus earnings forecasts from Bloomberg, Reuters, ValueLIne and Zacks.	9.3	McShane Evid, Table 30, p. 113; App. C, and Schedule 19
	Constant Growth	5 Can utilities (incl. Fortis Inc.)	7.5% - Reuters L-T EPS forecasts	11.0	McShane Evid, Table 30, p. 113 and Schedule 22
	Sustainable Growth	12 US Utilities	4.4% - Avg of sustainable growth rates for US utilities derived from Value Line forecasts of ROEs, earnings retention rates and earnings growth from external financing.	8.7	McShane Evid, Table 30, p. 113 and Schedule 20
	Three Stage Model	5 Can utilities (incl. Fortis Inc.)	Stage 1 (yrs 1-5) - Reuters L-T EPS forecasts: 7.5% Stage 2 (yrs 6-10)- Avg of stages 1 and 3: 5.9% Stage 3 (yrs 11+)-GDP growth: 4.3%	8.6	McShane Evid, Table 30, p. 113 App. C and Schedule 23
	Three Stage Model	12 US utilities	Stage 1 (yrs 1-5) - Avg of all EPS forecasts: 4.9% Stage 2 (yrs 6-10) - Avg of stages 1 and 3: 4.9% Stage 3 (yrs 11+) - GDP growth: 4.9%	9.2	McShane Evid, Table 30, p. 113 and Schedule 21
	Mid-point of range	Canadian sample		9.8	McShane Evid. p. 113
	Mid-point of range	Both samples		9.4	McShane Evid. p. 113
			Bare bones Cost of Equity estimated at 9.4% and add Financing Flexibility Adjustment of 0.5%	9.9	

...**DCF MODELS**

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Vander Weide	Quarterly DCF model	Comprehensive group of 32 US utilities	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.8	VdW Evid, p. 28 – 30 and Exhibit 6
		Small group of 19 US utilities (subset of large group)	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.5	VdW Evid, p. 28 – 30 and Exhibit 7
			Bare-bones cost of equity for the Comprehensive Model 9.8% plus Financing Flexibility	10.3	
			Bare-bones cost of equity for the Small Utilities Model 9.5% plus Financing Flexibility	10.0	
			Summary of results from DCF	10.15	
Booth		All of Canadian market	Growth rate range 4.7% - 6.1% based on multiplying corporate Canada ROEs since 1987 times retention rates.	9.3	Booth Evid., p. 94 & App D, p. 9-10
		US market – S&P 500	Growth rate range of 6.79% - 7.97% based on multiplying the average and median values respectively for S&P 500 ROEs since 1977 times the current dividend yield	Calculated range: 8.93-10.01. Adjusted range: 9.5-10.5	Booth Evid., App D, p. 10-13 (Note disc. of analyst forecasts at p. 14-17.)

...**DCF MODELS**

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Safir	Two-stage model	Canadian Sample - 5 Can. utilities (incl. Fortis)	Stage 1 (analyst forecasts)- 7.49%; Stage 2 (GDP growth) – 4.49% Weighted average (33/67): 5.49%	8.99	Safir Evid, p. 24-26, and Schedule 3
	Two-stage model	US Sample – 18 US utilities	Stage 1 (analyst forecasts) - 5.50%; Stage 2 (GDP growth) – 4.57% Weighted average (33/67): 4.88%	8.86	Safir Evid,p. 24-26, and Schedule 4
			ROE Adjusted by Flotation Costs at 5% for Canadian sample	9.46	Safir Evid. p. 26
			ROE Adjusted by Flotation Costs at 5% for US sample	9.33	Safir Evid. p. 26

CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	See her Risk-Adjusted Equity Risk Premium Model					
Vander Weide	N/A – Vander Weide recommends placing no weight on CAPM results	2.95% forecast yield to maturity on L-C bonds	6.6% - Ibbotson SBBI estimate of risk premium on market portfolio – diff. between arithmetic mean return on S&P 500 vs. income return on 20-year Treasury bonds. (1937-2012)	0.73 – Average Value Line beta for his large proxy US utility group.	8.27 (including financial flexibility)	Vander Weide Evid, pp. 38-44; Exhibits 12 to 15
				0.92 – historical ratio of the average utility risk premium to the S&P risk premium	9.52 (including financial flexibility)	
Booth	Simple CAPM estimate	3.00% (Base adjusted LTC forecast)	Range: 5.0 – 6.0%	Range: 0.45-0.55	Range: 5.75-6.80, including 0.50 flotation cost allowance	Booth Evid, p. 74 & 75; App. B (MRP), p. 16, App. C (beta est), pp. 10-14
	Adjusted CAPM (Simple CAPM plus 0.40 for credit spread and 0.80 for Operation Twist.	3.80% (Base adjusted LTC forecast)	Same as above	Same as above	Range: 6.95 to 8.00 (2013) 7.00 -8.00 Including flotation cost allowance	Booth Evid, p. 85, 93-94 (adjustments); other values same as above.
				Point estimate for CAPM	7.5	Booth Evid. p. 95

…CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
Safir	Canadian CAPM	4.00%	5.96% (Total mkt. return minus the est annual long bond income return (both 1924-2010)	Adjusted beta: 0.36 (weighted 0.67 raw + 0.33 mkt tendency) Calculated raw beta (Sched 1): 0.25 Long-run mkt tendency beta (Schaeffler & Weber survey): 0.58	6.15	Safir Evid. p. 12-15 and Schedule 1
	US CAPM	4.50%	6.62% (Total mkt. return minus the est annual long bond income return (both 1926-2011)	Adjusted beta: 0.48 (weighted 0.67 raw + 0.33 market tendency) Calculated raw beta (Schedule 2): 0.43 Long-run market tendency beta (Schaeffler & Weber survey): 0.58	7.68	Safir Evid. p. 18 and Schedule 2
				Adjusted by flotation cost allowance of 0.32% for the Canadian ROE estimate	6.47	Safir Evid. p. 12
				Adjusted by flotation cost allowance of 0.40% for the US ROE estimate	8.08	Safir Evid. p. 18

EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	Risk-adjusted ERP (variant of CAPM)	4.0% (forecast 30 yr Long-Can bond yield)	7.25-7.5% (based on bond income returns < 8.0%; table 12, pp. 82, 98 of her evid)	0.65-0.70 adjusted (0.65 based on Bloomberg adjusted betas for 5 Can utilities or raw beta for TSX utilities index adjusted per Bloomberg (.67 raw+0.33; see McShane evid. p. 97. For upper end of range see table 21, p. 98)	Range: 8.9-9.1% Est. 9.0%	McShane Evidence, p. 98
	DCF Based ERP Models: 1998-2012 Q1 US Sample					
	Constant Growth – Single variable (L-C bond rate)	4.0% (forecast 30 yr L-C yield)	5.7% at 4.0% risk free rate (see table 22, p. 100)	N/A	9.7%	McShane evid. p. 99-101
	3-stage growth - single variable	4.0%	5.7 or 5.8% at 4.0 risk free rate (apparent inconsistency between tables 24 and 25)	N/A	9.7	McShane evid p. 99-105
	Constant Growth – two variable (L-C bonds and 30 year A-rated utility yield spreads)	4.0%	5.5%	N/A	9.5	McShane evid at pp. 102-105, esp. table 25.
(cont….)	3-stage growth – two variable	4.0%	5.6%	N/A	9.6	McShane evid at pp. 102-105, esp. table 25.

…**EQUITY RISK PREMIUM MODELS**

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane (cont. from previous page)	*DCF Based ERP Models*: 1998-2012Q1 US Sample (continued from previous page)					
	Quarterly US utility ROE's as proxy for utility cost of equity – single variable	4.0%	6.2%		10.2 (McShane gives no weight)	McShane evid at pp. 102-105, esp. table 25
	Quarterly US utility ROE's– two variable	4.0%	6.1%		10.1 (no weight)	McShane evid at pp. 102-105, esp. table 25
	Constant Growth over A-rated bond	5.35% (4.0% L-C bond yield + 135 bp)	4.0		9.4	McShane evid at p. 105, table 26
	3-stage growth over A-rated bond	5.35% (as above)	4.2		9.6	McShane evid at p. 105, table 26
	Allowed ROEs over A-rated bond	5.35% (as above)	4.8		10.2 (no weight)	McShane evid at p. 105, table 26
(cont…)	Summary of results DCF based results	4.0%% (f'cast L-C bond yields) or 5.35% (A-rated utility bond yields	Range of regression results		9.4 – 9.7	McShane Evid. p. 106
			Bare bones Cost of Equity (mid-point)		9.6	

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Equity Returns	Bond Inc. Returns	Utility Risk Premium	Change in Bond Yield/Ret	Change in Util Risk Pr.	Utility Equity Risk	ROE est. (%)	References
McShane (cont. from previous page)	Historic Utility ERP- Can utilities (1956-2011)	4.0%	12.1%	7.3%	4.8%	-3.3%	+1.6%	6.4%	10.5 (based on all 3 Historic Utility ERP tests)	McShane Evid. pp. 106-108
	Historic Utility ERP- US Gas Utilities (1947-2011)	4.0%	11.9%	5.9%	6.0%	-1.9%	+1.0%	7.0%		McShane Evid. pp. 106-108
	Historic Utility ERP- US Elec Utilities (1947-2011)	4.0%	11.0%	5.9%	5.1%	-1.9%	+1.0%	6.2%		McShane Evid. pp. 106-108
	Summary of All Risk Premium Tests	Risk-Adjusted Equity Market							9.0	McShane Evid p. 109, table 29
		DCF-based							9.6	
		Historic Utility							10.5	

Vander Weide (cont…)			Stock Returns	Avg Bond Yields	Risk Premium	Expected bond yield		
	Ex-Post Risk Premium	S&P/TSX Utilities: 1956-2011	11.99%	7.33%	4.7%	N/A	N/A	Vander Weide Evid, pp. 32-35, 44; and Exhiibits 8 & 9
		BMO Utilities: 1983-2011	16.01	7.24	8.8%	N/A	N/A	
		Average risk premium of the two samples			6.7%	2.95%	10.15 (rounded to 10.2% (incl. 0.5% flotation	

…EQUITY RISK PREMIUM MODELS

Analyst	Model sub-Type	Sample Group and Period	DCF Growth rate	Risk Prem.	Risk Free Rate	Roe est. (%)	References
Vander Weide (cont. from previous page)	Ex-Ante Risk Premium	Natural Gas group selected from S&P nat. gas companies	DCF growth rate and analysis by individual company from I/B/E/S forecast of earnings growth for each month. (Exhibits 10 & 11)	8.0%	2.95%	11.5 (incl flotation)	Vander Weide Evid. pp. 35-38 and App. 3, Exhibits 10, 11 and 24
		Moody's group of 24 Electric utilities.		7.5%	2.95%	11.0 (incl flotation)	
Booth	N/A						
Safir	N/A						

COMPARABLE EARNINGS TESTS

Analyst	Model sub-Type	Sample Group and Period	ROE est. (%)	References
McShane	Book-value based	21 Canadian unregulated companies: 2004-2011 (incl downward adjustments of 125 to 150 bps)	Range: 11.0-12.0 Est: 11.5	McShane Evid, pp. 113-117, 119 and App E.
Vander Weide	N/A		N/A	
Booth	Book-value based	Corporate Canada (Statistics Canada reported earnings): 1987-2011, and TSX composite for the same period	Market ret: 9.3	Booth Evid. p. 93 and App. E, Schedule 2
Safir	Market-value based	Canadian sample: same 21 Canadian Companies as used by McShane: 2004-2011	6.85	Safir Evid. pp. 28-35 and Schedules 5 and 6
	Market-value based	US Sample: 31 US companies in the consumer goods, industrial goods or service sectors using same selection critiera as McShane used for her Canadian sample: 2004-2011.	5.81	
	Weighted average giving Canadian results twice the weight of the US results		6.50	

SUMMARY OF ROE RECOMMENDATIONS

Analyst	Method	Model Sub-Type	'Bare-bones' Cost of Equity"	Financing Flexibility Adjustment	ROE est. (%)	References
McShane	DCF		9.4%	0.50%	9.9	McShane Evid. pp. 6 and 119
	Risk Premium	Risk-Adj Equity Mkt	9.0%	0.50%	9.5	
		DCF-based	9.6%	0.50%	10.1	
		Historic Utility	10.5%	0.50%	11.0	
	Comp. Earning		N/A	N/A	11.5	
VanderWeide	DCF		9.5%	0.5%	10.15	Vander Weide Evid. p. 44 and Exhibit 7
	CAPM	Calulates ROEs (incl. flotation allowance) of 8.27% and 9.52% but gives the CAPM results no weight			N/A	Vander Weide Evid. p. 44 and Exhibits 12 and 13
	Risk Premium	Ex-Post RP	9.65%	0.50%	10.15 (10.2)	Vander Weide Evid. pp. 35, 38 and 44, and Exhibits 8, 9, 10, 11 and 24
		Ex-Ante RP (average of Natural Gas and Elec. Samples	10.75%	0.50%	11.25	
Booth	Discounted Cash Flow	All of Canadian market	9.28% for the market as a whole		N/A	Booth Evid. p. 93-94 and App. D, pp. 9-10
		US market – S&P 500	9.5% - 10.5% for the US market		N/A	
	CAPM	Adjusted for credit spread and Operation Twist	6.95-7.50%	0.50%	7.50	Booth Evid. pp. 93-94
	Comp. Earning	Market Returns	9.3% for Corporate Canada (StatsCan)		N/A	Booth Evid, p. 93-94; App. E, pp. 2-7
Safir	DCF	Canadian Sample	8.99%	0.47%	9.46	Safir Evid, p. 26
		US Sample	8.86%	0.47%	9.33	
	CAPM	Canadian Sample	6.15%	0.32%	6.47	Safir Evid. p. 12
		US Sample	7.68%	0.40%	8.08	Safir Evid. p. 18
		Weighted average	N/A	N/A	7.01	Safir Evid, p. 19
	Comp Earning	Market value based results; wighted avg of Can and US results			6.50	Safir Evid. p. 33

LIST OF ACRONYMS

AAM	Automatic Adjustment Mechanism
AECO	Alberta's gas trading price
AES	Alternative Energy Services
AMPC	Association of Major Power Consumers
AUB	Alberta Utilities Commission
B	Beta
BA	Bankers' Acceptances
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCUC	British Columbia Utilities Commission
BC Utility Customers	Collectively AMPC, BCPSO, CEC
bps	Basis points
CAPM	Capital Asset Pricing Model
CDOR	Canadian Dealer Offered Rate
CEC	Commercial Energy Consumers of B.C.
CEA	Clean Energy Act
Concentric	Concentric Economic Advisers
CPCN	Certificate of Public Convenience and Necessity
DCF	Discounted Cash Flow
ERP	Equity Risk Premium
FRS	Fair Return Standard
FBCU	FortisBC Utilities
Fl PUC	Florida Public Service Commission

LIST OF ACRONYMS

GCOC	Generic Cost of Capital
GJ	Gigajoule
ICG	Industrial Customers Group of FortisBC Inc.
LCBF	Long Canada Bond Forecast
NEB	National Energy Board
O&M	Operation and Maintenance
PBR	Performance Based Ratemaking
PNG	Pacific Northern Gas
PRMP	Price Risk Management Plan
OEB	Ontario Energy Board
ROE	Return on Equity
r_m	Expected return on the market
r_f	Risk free rate
$r_m - r_f$	Market risk premium
r_e	Opportunity cost of equity
Régie	Régie de l'Energie
TES	Thermal Energy Services
Terasen, TGI	Terasen Utilities, Terasen Gas Inc.
UCA	Utilities Commission Act
UPC	Use Per Customer

YEC-YECL-14

Reference: Section 8 – Return on Rate Base – Common Equity Ratio

Request:

(a) Please confirm that forecast common equity ratio is 43.61% for 2013, 43.66% for 2014 and 43.70% for 2015.

(b) Please explain the reason for increase in common equity ratio from 40.65% in 2012 to 43.61% in 2013.

(c) Please confirm that based on Schedule 8.1 the mid-year balance of common equity forecast to increase from $25.740 million in 2012 actual to $42.860 million in 2015, i.e. increase of $17.120 million over three years. Please provide forecast sources for this additional equity amount (parent company equity injections, retained earnings or other).

(d) Please update Schedule 8.1 by using 40% equity ratio and discuss impacts to the YECL to provide services to its customers.

(e) Please outline and explain in detail any changes in YECL's risk profile since the 2008/2009 GRA that would warrant an increase in equity ratio from 40%.

(f) Please explain the impact that the number of deferral accounts (Whitehorse Copper Tailings Sales Uncertainty, Purchased Power Flow Through, Depreciation Parameters, ROE and Defined Benefit Pension Plan proposed in the current application would have on YECL's risk profile.

Response:

(a) Yukon Electrical can confirm that the forecast common equity ratio is 43.61% for 2013, 43.66% for 2014 and 43.70% for 2015. However, when no cost capital is excluded, the forecast common equity ratio is 44.0% for 2013-2015. Please refer to YEC-YECL-14(a) Attachment 1 for a copy of Schedule 8.1 showing the equity ratio not including no cost capital.

(b) Yukon Electrical has requested an increase in equity ratio from 40% to 44% as part of its 2013-2015 GRA. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(c) Confirmed. The source of the additional equity amount will be parent company equity injections and retained earnings.

(d) Please refer to YEC-YECL-14(d) Attachment 1 for Schedule 8.1 updated for a 40% equity ratio. The requested 44% common equity ratio, based in part on a respect of the stand-alone principle, is required for Yukon Electrical to contribute its fair share towards the maintenance of CU Inc.'s A credit rating. As Yukon Electrical's debt mirrors the debt of CU Inc., Yukon Electrical's customers benefit from the low interest rates obtained by the A rated CU Inc.

(e) Please refer to YUB-YECL-31 addressing changes to Yukon Electrical's risk profile since the 2008/2009 GRA. Further, the increase in common equity ratio is based on the following increases in common equity ratios since Decision 2009-02:

BCUC's benchmark utility common equity ratio increased from 35.01% to 38.5%;

Northland Utilities (Yellowknife)'s common equity ratio increased from 39.57% to 43.5%; and

Northland Utilities (NWT)'s common equity ratio increased from 40% to 44%.

As noted in part (b) of this response, these changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility.

(f) As detailed below, there is no material change to Yukon Electrical's risk profile as a result of the deferral accounts requested as part of this 2013-2015 GRA Application as compared to the risk profile reviewed as part of the 2008/2009 GRA.

Whitehorse Copper Tailings – No industrial customers were forecast as part of Yukon Electrical's 2008/2009 GRA. The requested deferral therefore results in Yukon Electrical's risk profile remaining constant.

Purchased Power Flow Through – There is no change requested in this Application from the previously YUB approved deferral.

Depreciation Parameters – As detailed in Section 7 of its Application, the intension of Yukon Electrical's requested deferral is, to the extent possible, permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, the purpose of deferral is not to address Yukon Electrical's risk profile.

ROE - The proposed AAM and ROE deferral does not reduce Yukon Electrical's risk profile. BCUC is re-instituting an AAM as it has the potential to contribute to regulatory efficiency, and did not note in its decision any impact the AAM formula has on the risk profile of the benchmark utility.

Defined Benefit Pension Plan – In its 2008/2009 GRA, Yukon Electrical did not request a Defined Benefit Pension Plan deferral as its funding requirements for the test period were known based on the December 31, 2006 Actuarial Valuation. For purposes of this Application, the funding requirements for 2013, 2014 and 2015 are not known. The requested deferral therefore results in Yukon Electrical's risk profile remaining constant.

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Balance Excluding No Cost Capital	Ratio Excluding No Cost Capital	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**								
27	Long-Term Debt	S.8.3 L.23	40,150	55.52%	40,150	56.00%	40,154	5.99%	2,404
28	Common Stock		31,540	43.61%	31,540	44.00%	31,544	9.21%	2,904
29	No Cost Capital	S.8.4 L.8	632	0.87%			632	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,322	100.0%	71,690	100.0%	72,329	7.34%	5,308
31	**2014 Test Period**								
32	Long-Term Debt	S.8.3 L.48	47,950	55.58%	47,950	56.00%	47,835	5.84%	2,793
33	Common Stock		37,670	43.66%	37,670	44.00%	37,579	9.21%	3,462
34	No Cost Capital	S.8.4 L.8	651	0.75%			649	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,271	100.0%	85,620	100.0%	86,063	7.27%	6,255
36	**2015 Test Period**								
37	Long-Term Debt	S.8.3 L.73	54,550	55.62%	54,550	56.00%	53,845	5.77%	3,105
38	Common Stock		42,860	43.70%	42,860	44.00%	42,306	9.21%	3,898
39	No Cost Capital	S.8.4 L.8	670	0.68%			661	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	98,080	100.0%	97,410	100.0%	96,812	7.23%	7,003

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2008 Actual**						
2	Long-Term Debt	S.8.2 L.19	24,575	56.81%	26,100	6.97%	1,819
3	Common Stock		17,994	41.59%	19,110	7.03%	1,344
4	No Cost Capital	S.8.4 L.8	693	1.60%	735	0.00%	-
5	Total	S.8.5 L.21 S.1.1 L.15	43,262	100.0%	45,946	6.88%	3,163
6	**2009 Actual**						
7	Long-Term Debt	S.8.2 L.42	27,650	57.34%	28,166	6.73%	1,895
8	Common Stock		19,866	41.20%	20,236	11.35%	2,296
9	No Cost Capital	S.8.4 L.8	702	1.45%	715	0.00%	-
10	Total	S.8.5 L.21 S.1.1 L.15	48,217	100.0%	49,116	8.53%	4,191
11	**2010 Actual**						
12	Long-Term Debt	S.8.2 L.63	29,950	57.27%	28,649	6.58%	1,884
13	Common Stock		21,682	41.46%	20,740	10.54%	2,187
14	No Cost Capital	S.8.4 L.8	666	1.27%	637	0.00%	-
15	Total	S.8.5 L.21 S.1.1 L.15	52,298	100.0%	50,026	8.14%	4,071
16	**2011 Actual**						
17	Long-Term Debt	S.8.2 L.85	32,450	57.36%	30,062	6.42%	1,931
18	Common Stock		23,472	41.49%	21,745	10.74%	2,335
19	No Cost Capital	S.8.4 L.8	649	1.15%	601	0.00%	-
20	Total	S.8.5 L.21 S.1.1 L.15	56,571	100.0%	52,408	8.14%	4,266
21	**2012 Actual**						
22	Long-Term Debt	S.8.2 L.107	36,950	58.35%	35,031	6.16%	2,158
23	Common Stock		25,740	40.65%	24,403	10.18%	2,484
24	No Cost Capital	S.8.4 L.8	631	1.00%	598	0.00%	-
25	Total	S.8.5 L.21 S.1.1 L.15	63,321	100.0%	60,033	7.73%	4,642

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Schedule 8.1

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**						
27	Long-Term Debt	S.8.3 L.23	43,014	59.48%	43,018	5.88%	2,529
28	Common Stock		28,676	39.65%	28,679	9.21%	2,641
29	No Cost Capital	S.8.4 L.8	632	0.87%	632	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,322	100.0%	72,329	7.15%	5,170
31	**2014 Test Period**						
32	Long-Term Debt	S.8.3 L.48	51,372	59.55%	51,248	5.71%	2,926
33	Common Stock		34,248	39.70%	34,166	9.21%	3,147
34	No Cost Capital	S.8.4 L.8	651	0.75%	649	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,271	100.0%	86,063	7.06%	6,073
36	**2015 Test Period**						
37	Long-Term Debt	S.8.3 L.73	58,446	59.59%	57,691	5.69%	3,280
38	Common Stock		38,964	39.73%	38,460	9.21%	3,542
39	No Cost Capital	S.8.4 L.8	670	0.68%	661	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	98,080	100.0%	96,812	7.05%	6,822
41	**2008 GRA Approved**						
42	Long-Term Debt	S.8.2 L.126	26,621	59.11%	27,243	6.87%	1,870
43	Common Stock		17,747	39.41%	18,162	9.08%	1,649
44	No Cost Capital	S.8.4 L.8	669	1.49%	685	0.00%	-
45	Total	S.8.5 L.21 S.1.1 L.15	45,037	100%	46,090	7.64%	3,519
46	**2009 GRA Approved**						
47	Long-Term Debt	S.8.2 L.148	29,730	59.17%	29,276	6.60%	1,934
48	Common Stock		19,820	39.45%	19,517	8.92%	1,741
49	No Cost Capital	S.8.4 L.8	695	1.38%	684	0.00%	-
50	Total	S.8.5 L.21 S.1.1 L.15	50,245	100%	49,478	7.43%	3,675

YUB-YECL-1

Reference: Deferral Accounts, YECL Application, Page 1-5

The deferral accounts for which Yukon Electrical is seeking approval meet the standard criteria for the establishment of a deferral account:

Request:

(a) Please cite the regulatory body, regulation or rules which provide or state the criteria for a deferral account.

(b) For the seven deferral accounts listed on page 1-6, please state which criteria applies, and if the second criteria applies, please provide the analysis that determined that "an error in forecasting could produce a loss or a gain of a substantial magnitude".

(c) How did YECL manage these costs prior to the proposal of deferral accounts?

Response:

(a) Paragraph 12 of Board Order 2009-2 regarding Yukon Electrical's 2008/2009 GRA states the following, which is consistent with the criteria used by Yukon Electrical to determine which items warrant deferral treatment for 2013-2015:

> With respect to the proposed Pelly Crossing deferral account, the Board notes that the typical criteria used in determining whether to approve the use of a deferral account are the level of uncertainty regarding the accuracy of the forecast and the utility's ability to control the factors influencing the forecast.

Additionally, the two criteria for a deferral account outlined on pages 1-5 and 1-6 of the Application have been specifically tested, reviewed and approved in recent ATCO Electric applications to the AUC.

(b) For the seven deferral accounts for which Yukon Electrical is seeking approval, all are considered to be outside the control of the company and are not reasonably forecastable.

(c) Whitehorse Copper Tailings – This is a new industrial customer that is uncertain as to the exact timing of its start-up as well as its ultimate load. This area was not an issue for Yukon Electrical in its most recent GRAs as it was not forecasting industrial customers.

Purchased Power Flow Through – Yukon Electrical is requesting a continuation of the existing deferral account with no proposed changes.

Diesel Contingency Fund – Yukon Electrical is requesting a continuation of the existing deferral account with no proposed changes.

Fuel Price Flow Through – While Yukon Electrical is requesting a continuation of the existing deferral account, the request includes approval to change the methodology for calculating the deferral to include liquefied natural gas (LNG) as well as diesel fuel in Watson Lake. The purpose of this deferral continues to be to protect both customers and Yukon Electrical's shareowner from changes in fuel price as compared to forecast.

Depreciation Parameters – The intention of Yukon Electrical's requested deferral is, to the extent possible, permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, the purpose of deferral is not to address risk. This deferral addresses the advent of IFRS since Yukon Electrical's 2008-2009 GRA.

Rate of Return on Common Equity – In Board Order 2009-02, Yukon Electrical was directed for 2008 and 2009 to tie its ROE to the BCUC benchmark return on equity (ROE) for each respective year. As a result, the ROE for 2008 was set at 9.08% (BCUC benchmark ROE + 0.46% risk premium) and the ROE for 2009 was a placeholder, to be set at 46 basis points above the BCUC 2009 benchmark ROE (which ended up being 8.47%). As the 2009 BCUC benchmark ROE was known by the time Yukon Electrical completed its compliance filing, no deferral or true-up was required as it was incorporated in base rates.

Using the same methodology as it was directed to use in 2008 and 2009, Yukon Electrical has requested approval to set its ROE at the BCUC benchmark ROE + 0.46% for 2013-2015. As the BCUC has set the benchmark ROE at 8.75% with no AAM for 2013, Yukon Electrical has not requested a deferral for 2013. For 2014 and 2015, as there is an AAM that may impact the BCUC benchmark ROE for those years and because such a change may not be known at the time of Yukon Electrical's compliance filing related to this proceeding,

Yukon Electrical is requesting a deferral to flow the impact from the AAM, if any, through to customers for the years 2014 and 2015.

Defined Benefit Pension Plan – When Yukon Electrical filed its last GRA in 2008, Federal pension regulations in place required updated actuarial valuations to be completed for defined benefit ("DB") pension plans at least once every three years. An actuarial valuation for the DB plan that Yukon Electrical participates in was completed as at December 31, 2006 to determine the required funding for the years 2007-2009. As a result, the level of the required contributions to the plan was known for the three year period 2007-2009 and, more specifically, for the test period of 2008-2009. Since 2009, Yukon Electrical has contributed to its DB plan based on the results of the actuarial valuations that were prepared during this period. As part of this 2013 – 2014 Application, Yukon Electrical is requesting a deferral account that maintains risk at a status quo level as compared to the 2008-2009 test period.

YUB-YECL-2

Reference: Deferral Accounts, YECL Application, Page 1-6

Request:

Please explain how depreciation parameters, rate of return on common equity and the defined benefit pension plan are not under the control of the company.

Response:

Depreciation Parameters

Events which could potentially lead to a change in life depreciation parameters include: functional obsolescence or inadequacy, technological change, changing requirements of customers and market forces, customer growth, and legal and regulatory requirements. Net salvage can be affected by changes in technology in the removal of property, inflation (which can significantly affect removal costs), and changes in market demand and market prices which can affect salvage values. None of these events are under the control of the company.

Rate of Return on Common Equity

The BCUC benchmark return on equity for 2014 and 2015 is subject to an automatic adjustment mechanism (AAM) that will become operative if a long term Canadian bond yield of 3.8% is met or exceeded. Yukon Electrical does not have any control over the calculation of the AAM or long term Canadian bond yields and, consequently, does not have any control over the benchmark return on equity for 2014 and 2015.

Defined Benefit Pension Plan

Federal pension regulations require the defined benefit pension plan in which Yukon Electrical participates to file an actuarial valuation which sets out funding requirements. The valuation report is prepared by Mercer (Canada) Limited in accordance with applicable pension legislation and actuarial standards of practice in Canada. The results of the valuation and, consequently, the funding requirements are impacted by actuarial assumptions such as investment returns, inflation rates and demographic and societal factors, which are not under the control of Yukon Electrical.

YUB-YECL-4

Reference: IFRS, YECL Application Section 1, Attachment 2

Request:

Of the 24 boxes listed in Attachment 2, 21 list the change to IFRS as having either no change or the proposed treatment has no impact. Please comment on how this may affect accounting and administrative costs for YECL.

Response:

Of the 24 boxes listed in Attachment 2, 21 are described as having no impact on this Application. That is, for the purpose of this regulatory filing, Yukon Electrical has continued to treat the items the same as would have been the case under Canadian GAAP and, accordingly, there is no impact to Yukon Electrical's revenue requirement as a result of the transition to IFRS. For the 3 remaining items that were not specifically identified as not being impacted by the change to IFRS (Regulatory Assets and Liabilities: Deferral Accounts, Deferred Charges and Depreciation), there was also no impact to Yukon Electrical's revenue requirement for 2013-2015 as a result of the transition to IFRS.

Further to the above, however, many of the items listed are now required to be treated differently for financial statement purposes under IFRS than they were treated under Canadian GAAP. Some of the more notable differences include:

- Regulatory Assets and Liabilities: Deferral Accounts – deferral accounts must continue to be recorded for regulatory purposes, but IFRS does not permit the recording of deferral accounts on the balance sheet;

- Capitalization/Non-Capitalization of Costs: Borrowing Costs/Equity Allowance for Funds Used During Construction (AFUDC) – calculation of borrowing costs to be capitalized for IFRS (interested during construction) is different than the standard regulatory method of calculating AFUDC;

- Treatment of Insurance Proceeds – insurance proceeds related to the loss of property, plant and equipment are recognized in income under IFRS while they are considered proceeds of disposition for rate-making purposes;

- Depreciation – Canadian GAAP permitted regulatory companies to record depreciation based on the depreciation parameters set by the latest depreciation study, while IFRS requires an annual review of depreciation parameters and the immediate implementation of new parameters if they are found to have changed materially;

- Accounting for Income Taxes – Yukon Electrical records taxes based on the amount actually payable or receivable in the current year for regulatory reporting, but is required to recognize both current and deferred income taxes under IFRS;

- Pension Costs/ Other Employment Benefits – IFRS requires these items to be recorded on the accrual basis while, for regulatory purposes, Yukon Electrical recognizes pension and OPEB costs on the cash basis; and

- Reserve for Injuries and Damages and Rate Case Reserve – costs are expensed in the year incurred under IFRS.

All of these items requiring different treatment for regulatory and financial statements purposes can result or have resulted in Yukon Electrical being required to maintain two sets of financial records. Maintaining two sets of records adds complexity and additional reconciliation requirements to reporting for both regulatory and financial statement purposes. As well, there are now two sets of “rules” that accountants at Yukon Electrical have to understand and consider when recording transactions.

YUB-YECL-5

Reference: Defined Pension Benefit, YECL Application, Page 5-3, YECL Application, Schedule 5-1 and Schedule 5-2

For the purposes of this Application, the 2013 test period assumes the same defined benefit contribution rates as 2012. Since the next defined benefit pension actuarial evaluation will be completed as of December 31, 2012 to determine 2013 required funding, any required change to the 2013 defined benefit pension funding requirements will impact the defined benefit pension expense related to YECL's eligible northern based staff. Beginning in 2013, YECL is requesting a deferral account to flow through the increases or decreases to required cash contributions to the company's defined benefit pension plan as a result of the required annual actuarial evaluations.

The Board seeks clarification in relation to defined benefit pension actuarial evaluation and the forecast pension costs during the test period.

Request:

(a) YECL submitted that the pension valuation will be completed by December 31, 2012. Please explain whether or not YECL is able to provide an update as to what the actual pension cost for 2013. If confirmed, please explain how this will affect YECL's O&M forecasts for 2013, 2014, and 2015.

(b) Please describe whether YECL will complete another defined benefit pension actuarial evaluation during the test period. If YECL is not expecting to complete another actuarial evaluation during the test period, please indicate when YECL expects to complete another one.

(c) Please explain whether YECL shares a pension plan with its ATCO affiliates. If not, please provide more details about the nature of this pension plan.

(d) If YECL shares a pension plan with its ATCO affiliates, describe whether YECL's regulated affiliates in other Canadian jurisdictions have a deferral account for their defined benefit pension plans. If yes, please describe this treatment (e.g. only current service portion, only special payments, or both).

(e) Schedule 5.1 does not provide an account for pension expense. Please provide a table showing the pension expense for 2008, 2009, 2010, 2011, and 2012, and where applicable, indicate the YECL forecasted pension expense YECL and the

actual pension expense for these years. Also break these costs into those attributable to current service payments and those attributable to special payments.

(f) Please describe which accounts in schedule 5.1 are affected by pension expenses and breakout the pension expenses from these accounts (i.e. show the account amounts less expenses attributable to pension benefits).

(g) Please indicate what percentage of YECL employees are under a defined benefit pension plan versus a defined contribution pension plan? Can new employees to YECL be covered under a defined benefit pension plan?

Response:

(a) The pension valuation as at December 31, 2012 was completed in July 2013. Please refer to YUB-YECL-5(a) Attachment 1 for a copy of the valuation.

As a result of this valuation, Yukon Electrical's required DB pension funding for 2013 is as follows:

Current service	$605,000
Special payment	$351,000
Total	$956,000

The impact on forecast O&M for 2013 is a decrease of $203,000 ($1,268,000 – 956,000 = 312,000 x 65% = $203,000).

This valuation does not have an impact on the O&M forecasts for 2014 and 2015 as the required DB pension funding for each of those years is not known at this time. An actuarial valuation as at December 31, 2013 will be completed in the second or third quarter of 2014 to determine the 2014 funding requirements and a valuation as at December 31, 2014 will be completed in the second or third quarter of 2015 to determine the 2015 funding requirements.

(b) Yes, Yukon Electrical will complete a defined benefit pension actuarial evaluation for each year during the test period.

The Pension Benefits Standard Act ("the Act") is the legislation that governs Federally-registered defined benefit pension plans such as the plan Yukon Electrical participates in. Regulations made under the Act set out

minimum funding requirements and conditions for when an updated defined benefit pension actuarial valuation is required to be prepared.

Regulations amending certain regulations made under the Act, which came into force on July 1, 2010, now generally require the filing of an actuarial valuation report on an annual basis. As a result, Yukon Electrical will be required to complete a defined benefit pension actuarial valuation as at December 31, 2013 in the second or third quarter of 2014 to determine the 2014 funding requirements and to complete a valuation as at December 31, 2014 in the second or third quarter of 2015 to determine the 2015 funding requirements.

(c) Yukon Electrical does share a pension plan with its ATCO affiliates. Canadian Utilities Ltd. (CU) sponsors two pension plans: Plan 1 (DB and DC) and Plan 2 (DB only). Yukon Electrical employees who are members of the DC plan participate in Plan 1. Yukon Electrical employees who are members of the DB plan participate in Plan 2 along with employees of other CU subsidiary companies located in the Yukon Territory, Northwest Territories, Nunavut and Ontario, such as Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited.

(d) Beginning in 2013, both Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited have deferral accounts approved to flow through all increases or decreases to required non-capitalized related cash contributions to the defined benefit pension plan. This includes both the current service and special payment portions of the contributions.

Both ATCO Electric – Distribution and ATCO Gas are under Performance-Based Regulation ("PBR") beginning in 2013. The existing special payment deferral accounts of both companies covering special payments were discontinued upon the implementation of PBR. However, in the event of a material change in pension obligations (either positively or negatively), a Z factor application would be available to address the change. Similar to a deferral, a Z factor application is a mechanism that allows a utility to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan period.

For its 2011-2012 GTA, ATCO Electric – Transmission had a deferral account approved to flow through changes in cash contributions for the special payment portion of required defined benefit funding. However, in its 2013-2014 GTA, filed

in June 2012, ATCO Electric – Transmission has requested to change the deferral to include both the current service and special payment portions of the required funding.

For 2011-2012, ATCO Pipelines had a deferral account approved to flow through changes in cash contributions for the special payment portion of required defined benefit funding. However, in its 2013-2014 GRA, filed in December 2012, ATCO Pipelines has requested to change the deferral to include both the current service and special payment portions of the required funding.

(e) Please refer to YUB-YECL-5(e) Attachment 1 for total pension expense included in Schedule 5.1.

(f) Any account on Schedule 5.1 that includes salaries and wages expenses is affected by pension, as benefit expenses are allocated to each account based on salaries and wages. Please refer to YUB-YECL-5(f) Attachment 1 for a revised schedule 5.1 showing the account amounts less expenses attributable to pension benefits.

(g) At December 31, 2012, 36% of active Yukon Electrical employees were members of the defined benefit pension plan while 64% of active employees were members of the defined contribution pension plan.

In general, new employees to Yukon Electrical are not eligible to be covered under the DB pension plan as it has been closed to new entrants since January 1, 1997. However, new employees to Yukon Electrical who transfer from an ATCO affiliate who were already covered under a DB pension plan sponsored by Canadian Utilities Ltd. continue to be part of the DB pension plan.

MERCER

TALENT • HEALTH • RETIREMENT • INVESTMENTS

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2012
RETIREMENT PLAN FOR EMPLOYEES OF CANADIAN UTILITIES LIMITED AND PARTICIPATING COMPANIES – PLAN 2

JULY 2013

Office of the Superintendent of Financial Institutions Registration Number: 56344
Canada Revenue Agency Registration Number: 0955138

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound up in the future. In fact, even if the plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the *Pension Benefits Standards Act*, the *Income Tax Act* and related regulations that are effective as of the valuation date. Mercer is not engaged in the practice of law or tax advice. This report does not constitute and is not a substitute for legal advice.

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Summary of Results

	31.12.2012	31.12.2011
Going Concern Financial Status		
Market / Smoothed value of assets	$31,843,600	$29,540,500
Going concern funding target	$36,073,600	$37,908,900
Funding excess (shortfall)	($4,230,000)	($8,368,400)
Hypothetical Wind-up Financial Position		
Wind-up assets	$31,643,600	$29,550,200
Wind-up liability	$37,725,500	$33,571,200
Wind-up excess (shortfall)	($6,081,900)	($4,021,000)
Funding Requirements in the Year Following the Valuation[1]		
Total current service cost	$728,100	$886,800
Estimated members' required contributions	($46,000)	($52,000)
Estimated employer's current service cost	$682,100	$834,800
Expense allowance	$60,000	$60,000
Total	$742,100	$894,800
Employer's current service cost as a percentage of members' pensionable earnings	30.31%	32.79%
Minimum special payments	$469,100	$877,680
Estimated minimum employer contribution	$1,211,200	$1,772,500
Estimated maximum eligible employer contribution	$6,824,000	$9,263,200
Next required valuation date	31.12.2013	31.12.2012

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To The Management Pension Committee of Canadian Utilities Limited

At your request, we have conducted an actuarial valuation of the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies - Plan 2 (the "Plan"), sponsored by Canadian Utilities Ltd. (the "Company"), as at the valuation date, December 31, 2012. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the plan as at December 31, 2012 on going concern, hypothetical wind-up and solvency basis;
- The minimum required funding contributions from 2013, in accordance with the *Pensions Benefits Standards Act, 1985* (the "Act"); and
- The maximum permissible funding contributions from 2013, in accordance with the *Income Tax Act*.

The information contained in this report was prepared for the internal use of the Company and for filing with the Office of the Superintendent of Financial Institutions ("OSFI") and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the OSFI and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2013, or as at the date of an earlier amendment to the Plan.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, we have reflected a margin for adverse deviations in our going concern valuation by reducing the going concern discount rate by 2.1% per year after January 1, 2020.
- We have reflected the Company decisions for determining the solvency funding requirements. Specifically, the same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2011

Pension Plan

There have been no special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2012. The Plan has not been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	**Previous valuation**
Discount rate:	6.10% initially, then 4.00% starting in 2020	6.10% initially, then 3.30% starting in 2020
Indexing rate:	1.85%	2.00%
Pensionable earnings increases:	3.25% plus merit & promotion	3.75% until 2012, 3.25% thereafter, plus merit and promotion
Termination rates:	No termination	100% of Plan experience 1983 through 1985
Asset valuation method:	Market	Smoothed

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going concern methods and assumptions is provided in Appendix C. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

There have been no changes to the *Pension Benefits Standards Act* (the "Act") or the relevant regulations which impact the funding of the Plan.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

We have assumed that all the Plan's assets are available to cover the Plan's liabilities presented in this report.

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Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	12.31.2012	12.31.2011
Assets		
Market value of assets	$32,958,400	$30,993,600
In-transit amount	($1,114,800)	($1,393,400)
Asset smoothing adjustment	$0	($59,700)
Smoothed value of assets	$31,843,600	$29,540,500
Going concern funding target		
• Active members	$20,288,900	$25,820,900
• Pensioners and survivors	$15,360,800	$11,632,100
• Deferred pensioners	$423,900	$455,900
Total	$36,073,600	$37,908,900
Funding excess (shortfall)	($4,230,000)	($8,368,400)

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		($8,368,400)
Interest on funding excess (funding shortfall) at 6.10% per year		($510,500)
Employer's special payments, with interest		$906,200
Expected funding excess (funding shortfall)		($7,972,700)
Net experience gains (losses)		
• Net Investment return	$595,300	
• Increases in pensionable earnings	($79,500)	
• Increase in YMPE	($4,900)	
• Increase in maximum pension	$12,900	
• Indexation	$107,200	
• Mortality	($11,300)	
• Retirement	$152,100	
• Termination	($69,300)	
• Net inter-plan transfers	($16,100)	
Total experience gains (losses)		$686,400
Impact of changes in assumptions		
• Discount rate	$2,629,100	
• Indexation rate	$763,600	
• Termination decrement	($162,700)	
Total assumption changes impact		$3,230,000
Impact of change in asset valuation method		$175,800
Net impact of other elements of gains and losses		($349,500)
Funding excess (shortfall) as at current valuation		($4,230,000)

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

	2013	2012
Total current service cost	$728,100	$886,800
Estimated members' required contributions	($46,000)	($52,000)
Estimated employer's current service cost	$682,100	$834,800
Expense allowance	$60,000	$60,000
Total	$742,100	$894,800
Employee's current service cost expressed as a percentage of members' pensionable earnings.	1.97%	1.91%
Employer's current service cost expressed as a percentage of members' pensionable earnings.	30.31%	32.79%
Total current service cost expressed as a percentage of members' pensionable earnings.	32.28%	34.70%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	32.79%
Demographic changes	1.02%
Assumption changes	(3.50%)
Employer's current service cost as at current valuation	30.31%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern funding target shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Going concern funding target	$36,073,600	$42,456,600
Current service cost		
• Total current service cost	$728,100	$895,700
• Estimated members' required contributions	($46,000)	($46,000)
• Estimated employer's current service cost	$682,100	$849,700
• Expense allowance	$60,000	$60,000
Total	$742,100	$909,700

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Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	12.31.2012	12.31.2011
Assets		
Market value of assets	$32,958,400	$30,993,600
In transit amount	($1,114,800)	($1,393,400)
Termination expense provision	($200,000)	($50,000)
Wind-up assets	$31,643,600	$29,550,200
Present value of accrued benefits for:		
• active members	$16,505,000	$19,322,500
• pensioners and survivors	$20,599,300	$13,684,600
• deferred pensioners	$621,200	$564,100
Total wind-up liability	$37,725,500	$33,571,200
Wind-up excess (shortfall)	($6,081,900)	($4,021,000)

Wind-up Incremental Cost to December 31, 2013

The wind-up incremental cost is an estimate of the present value of the projected change in the hypothetical wind-up liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The hypothetical wind-up incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	12.31.2012	12.31.2011
Number of years covered by report	1 year	1 year
Total hypothetical wind-up liabilities at the valuation date (A)	$37,725,500	$33,571,200
Present value of projected hypothetical wind-up liability at the next required valuation plus benefit payments until the next required valuation (B)	$39,996,900	$35,823,600
Hypothetical wind-up incremental cost (B – A)	$2,271,400	$2,252,400

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a hypothetical wind-up basis unchanged from the valuation date and the next required valuation date, if actual experience is exactly in accordance with the going concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the hypothetical wind-up liabilities shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total hypothetical wind-up liability	$37,725,500	$43,794,300

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Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	Reflected in valuation based on the terms of engagement
The circumstance under which the Plan is assumed to be wound up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up valuation.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Under the Federal pension legislation, the minimum funding requirements on a solvency basis are based on an alternative solvency basis under which the solvency deficiency and the resulting solvency special payments are based on an average solvency ratio determined over three years (current year plus the previous two) subject to prescribed adjustments. The determination of the solvency deficiency on that basis is detailed in Appendix A. The unadjusted solvency deficiency at the current valuation is presented below.

Financial Position

The financial position on a solvency basis is the same as the financial position on the Hypothetical Wind-up Basis shown in the previous section. The solvency ratio is 83.9% compared to 88.0% at the previous valuation.

6

Minimum Funding Requirements

The Act prescribes the minimum contributions that Canadian Utilities Ltd. must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions	
Period beginning	Monthly current service cost[2]	Minimum monthly special payments	Monthly current service cost including expense allowance	Total minimum monthly contributions
December 31,2012	30.31%	$39,090	$61,842	$100,932

The estimated contribution amounts above are based on projected members' pensionable earnings. If current service cost contributions are based on a percentage of members' pensionable earnings, then the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

Alternatively, as the Plan is closed to new employees and therefore the active membership is declining, it would be acceptable to contribute the above dollar amount of total minimum monthly contributions to the Plan.

The development of the minimum special payments is summarized in Appendix A.

Other Considerations

Differences between Valuation Basis

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the

[2] Expressed as a percentage of members' pensionable earnings capped at $150,164 per member.

hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of Contributions

Required contributions must be remitted monthly, not later than 30 days after the end of the period to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution is due immediately following the date this report is filed.

Any over contributions made prior to filing this report may be used to reduce the otherwise required contributions to be made following the filing of this report.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the solvency ratio revealed in an actuarial valuation is less than one. If the solvency ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Specifically, based on the Directives of the Superintendent of Financial Institutions pursuant to the Act, transfers out of the Plan may be made in full provided an amount equal to the transfer deficiency has been remitted to the pension fund in addition to the minimum special payments.

However, transfer deficiencies that are less than 5% of the Year's Maximum Pensionable Earnings ("YMPE") under the Canada/Quebec Pension Plan can be paid in full until such time as the sum of all such transfer deficiencies paid since the date of the last actuarial valuation exceed 5% of the market value of the Plan assets at that date, at which time, this exemption no longer applies.

As such, the administrator should monitor the solvency ratio of the Plan and, if necessary, take the prescribed actions.

7

Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. However, notwithstanding the limit imposed by the ITA, for plans which are not 'Designated' as defined in the ITA, in general, the minimum required contributions under the Act can be remitted.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up basis, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up basis, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

The Company is permitted to fully fund the greater of the going concern and hypothetical wind-up shortfalls; $6,081,900, as well as make current service cost contributions. The portion of this contribution representing the payment of the going concern funding shortfall can be increased with interest at 6.10% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

Assuming the Company contributes the greater of the going concern and hypothetical wind-up shortfall of $6,081,900 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions
Year beginning	**Monthly current service cost[3]**	**Deficit Funding**	**Monthly current service cost**
December 31, 2012	30.31%	n/a	$61,842

[3] Expressed as a percentage of members' pensionable earnings capped at $150,164 per member.

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

8

Actuarial Opinion

In our opinion, for the purposes of the valuations:

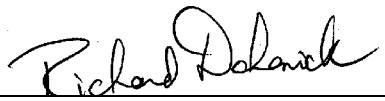
- the membership data on which the valuation is based are sufficient and reliable
- the assumptions are appropriate
- the methods employed in the valuation are appropriate

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pensions Benefits Standards Act*, 1985.



Mark Greenwood
FCIA, FIA

July 30, 2013
Date



Richard Dahonick
ASA

July 30, 2013
Date

APPENDIX A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Going concern excess (deficit)	Amount by which the going concern assets exceed (are below) the going concern liabilities	($4,230,000)
Unfunded liability	The amount by which the going concern deficit of a plan determined at the valuation date exceeds the present value of going concern special payments of the plan established in respect of periods after the valuation date	$0
Going concern special payment	A special payment made in respect of an unfunded liability	$469,100
Solvency Liabilities	Liabilities that relate to defined benefit provisions and which are determined on the basis that the plan is terminated	$37,725,500
Solvency Assets	Market value of the assets that relate to the defined benefit provisions of a plan minus the estimated expense of the winding-up of the plan	$31,643,600
Solvency Ratio	Ratio of the solvency assets to the solvency liabilities, excluding those solvency assets and solvency liabilities that are attributable to benefits that are paid by means of an annuity, other than a revocable annuity, or an insurance contract	0.839
Average Solvency Ratio	Arithmetic average of the solvency ratios at the valuation date, the prior valuation date and the prior second valuation date adjusted as prescribed for special payments, contribution holidays, amendments and transfer of assets	0.984
Adjusted Solvency Asset Amount	Amount determined by multiplying the average solvency ratio by the amount of the solvency liabilities	$37,113,100
Solvency excess (deficiency)	Amount by which the adjusted solvency asset amount exceeds (is below) the solvency liabilities	($612,400)
Solvency special payment	A special payment made in respect of a solvency deficiency	$0

Timing of Next Required Valuation

In accordance with the Act and the Superintendent's Directives, an actuarial report must be prepared annually except where the solvency ratio disclosed in the most recent actuarial report filed under subsection 12(3) of the Act was 1.20 or greater.

Accordingly, the next valuation of the Plan will be required as of December 31, 2013.

Special Payments
Going Concern Basis

The present values, at the current valuation date, of the monthly going concern special payments determined in the previous valuation, are as follows:

Present Value of Going Concern Monthly Special Payments from the Previous Valuation

Type of Deficit	Effective Date	Special Payment	Last Payment	Present Value at the Current Valuation Date
Going concern	December 31, 2006	$9,510	December 31, 2021	$797,200
Going concern	December 31, 2009	$26,430	December 31, 2024	$2,762,800
Going concern	December 31, 2011	$37,200	December 31, 2026	$4,354,200
Total		$73,140		$7,914,200

Since the present value of the going concern special payments, $7,914,200, exceeds the going concern deficit at the valuation date, $4,230,000, the excess shall be used, as per the Act and regulations, to reduce the going concern special payments on a pro rata basis as follows:

Minimum Going Concern Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment	Present Value at the Current Valuation Date
Going concern	December 31, 2006	$5,080	December 31, 2021	$426,100
Going concern	December 31, 2009	$14,130	December 31, 2024	$1,476,600
Going concern	December 31, 2011	$19,880	December 31, 2026	$2,327,300
Total		$39,090		$4,230,000

Solvency Basis

In accordance with the Act and regulations, the solvency excess (deficiency) is defined as the amount by which the adjusted solvency asset amount exceeds (is below) the solvency liabilities. For this purpose, the adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio, adjusted solvency asset amount and solvency excess (deficiency) are determined as follows:

Determination of Average Solvency Ratio

	12.31.2010	12.31.2011	12.31.2012
Solvency assets			
Market value of assets	$29,819,300	$29,600,200	$31,843,600
Termination expense provision	($50,000)	($50,000)	($200,000)
Solvency assets (A)	$29,769,300	$29,550,200	$31,643,600
Present value of special payments made (contribution holiday) (B)			
2011	$421,200	n/a	n/a
2012	$820,400	$862,400	n/a
Solvency assets adjusted for special payments (contribution holiday) (C = A + B)	$31,010,900	$30,412,600	$31,643,600
Solvency liabilities (D)	$25,701,100	$33,571,200	$37,725,500
Adjusted solvency ratio (C / D)	120.7%	90.6%	83.9%
Average solvency ratio (E)			98.4%

Calculation of adjusted solvency asset amount and solvency excess (deficiency)

	12.31.2012
Average solvency ratio (E)	98.4%
Solvency liabilities (F)	$37,725,500
Adjusted solvency asset amount (G = E x F)	$37,113,100
Solvency excess (deficiency) (G – F)	($612,400)

If there is a solvency deficiency, the Act and regulations require that solvency special payments be made in an amount equal to the amount by which the solvency deficiency divided by five exceeds the amount of going concern special payments that are payable during the year.

Minimum Solvency Special Payments

	2013
Solvency deficiency divided by five	$122,500
Going concern special payments	$469,100
Solvency special payments (not below $0)	$0

Total Special Payments

The following minimum monthly special payments must be made to the plan to eliminate any going concern deficit and any solvency deficiency at the valuation date, within the periods prescribed by the Act and regulations.

Minimum Monthly Special Payments

	2013
Going concern special payments	$39,090
Solvency special payments	$0
Minimum monthly special payment	$39,090

APPENDIX B

Plan Assets

The pension fund is held by RBC Investor Services. In preparing this report, we have relied upon fund statements prepared by RBC Investor Services without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2012
January 1	30,993,618
PLUS	
Members' contributions	58,984
Company's contributions	1,805,397
Inter-plan transfers	(1,385,521)
Investment income	1,464,696
Net capital gains (losses)	1,055,203
LESS	
Pensions paid	985,311
Lump-sum refunds	-
Administration fees	48,656
December 31	32,958,410
Gross rate of return[4]	8.20%
Rate of return net of expenses[4]	8.04%

[4] Assuming mid-period cash flows.

The market value of assets shown in the above table is adjusted to reflect in-transit amounts as follows:

	Current Valuation	Previous Valuation
Market value of invested assets	$32,958,410	$30,993,618
In-transit amounts		
• Transfers to Plan 1	($1,114,793)	($1,393,398)
Market value of assets adjusted for in-transit amounts	$31,843,617	$29,600,220

We have tested the pensions paid, the lump-sums paid and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy Target	Actual Asset Mix as at December 31, 2012
Fixed Income	50.0%	46.3%
Canadian equity	25.0%	27.3%
Global equity	25.0%	25.6%
Cash	0.0%	0.8%
	100.0%	100.0%

APPENDIX C

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets.

For the previous valuation, an adjusted market-value method to determine the smoothed value of assets was used. Under this method, 50% of realized and unrealized capital gains (losses) arising during a given year are recognized immediately and the remaining 50% of realized and unrealized capital gains (losses) arising during a given year are spread on a straight-line basis over three years in accordance with the schedule shown in the following table:

Year	Percentage of Gains (Losses) not Recognized
2011:	50% of 2/3
2010:	50% of 1/3
Before 2010	0%

Due to the expectation that the solvency position of the plan will determine the plan's minimum funding requirements in the future, we have discontinued the use of this adjusted market-value method.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to meet the plan's cash flow requirements in respect of accrued benefits and absent additional contributions.

As required under the Act, a funding shortfall will be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost can be expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. As the plan is closed to new members, the current service cost as a percentage of members' pensionable earnings is expected to increase as the average age of the members increases.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	6.10% initially, then 4.00% starting in 2020	6.10% initially, then 3.30% starting in 2020
Explicit expenses:	$60,000	$60,000
Inflation:	2.00%	2.00%
ITA limit / YMPE increases:	2.25%	2.25%
Pensionable earnings increases:	3.25% plus merit and promotion	3.75% until 2012, 3.25% thereafter, plus merit and promotion
Post retirement pension increases:	1.85%	2.00%
Retirement rates:	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55

Assumption	Current valuation	Previous valuation
Termination rates:	None	100% of Plan experience 1983 through 1985
Mortality rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using Scale AA	Fully generational using Scale AA
Disability rates:	None	None
Eligible spouse at retirement:	Based on current marital status	Based on current marital status
Spousal age difference:	Actual age if known (otherwise male 4 years older)	Actual age if known (otherwise male 4 years older)

The assumptions are best estimates with the exception that the discount rate includes a margin for adverse deviations, as described below in the Rationale for Assumptions.

Age Related Tables

Sample rates from the age related tables are summarized in the following table:

Age	Merit and Promotion
20	13.65%
25	6.02%
30	3.08%
35	1.75%
40	1.07%
45	0.70%
50	0.47%
55	0.33%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken the member's 2012 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using two different rates. Prior to 2020, the discount rate is based on the expected investment return on the market value of the fund.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- A margin for adverse deviations of 2.10% after January 1, 2020.

We have also observed that the defined benefit program is closed to new entrants and therefore the requirements under the Act will eventually become dominated by the solvency considerations, which in turn are dominated by annuity purchase rates. The discount rate after 2020 partially reflects this lower rate, as instructed by the Company.

The discount rate was developed as follows:

	Before 1.1.2020	After 1.1.2020
Assumed investment return	6.10%	6.10%
Margin	(0.00%)	(2.10%)
Net discount rate	6.10%	4.00%

Expenses

The explicit assumption is based on the average amount of investment and administrative expenses over the last 3 years.

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on our best estimate of future merit and promotional increases over general wage growth considering current economic and financial market conditions. Such merit and promotion increases are assumed to be in accordance with the table developed based on an experience study considering increases over the years 1985 to 1992 and which has continued to be reasonably predictive of merit and promotion increases experienced since that time.

Post Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above, considering that the Plan limits pension increases to 3% in the event that inflation exceeds 3%. We have determined the impact of this cap by performing a stochastic analysis based on trials using a mean of 2.0% and a standard deviation of 1.5%.

Retirement Rates

For this valuation we have continued to assume that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately. This assumption is based on the Plan provisions and our experience of similar pension plans.

Retirement earlier than assumed will result in losses to the Plan, while later retirements will result in gains to the Plan. These gains and losses will be revealed in subsequent valuations.

Termination Rates

As the Plan is closed, most active members are now eligible for retirement. The termination decrement assumption no longer has a material impact on the Plan's funding.

Mortality Rates

Due to the size of the Plan, there is no meaningful mortality experience but there is no reason to expect the mortality to differ from the 1994 Uninsured Pensioners mortality table. Furthermore, there is strong evidence of continuing improvement in mortality since 1994 and it has become an industry standard to assume this trend continues into the future. We have used the AA projection scale to allow for improvements in mortality indefinitely in the future.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 19.8 years for males and 22.0 years for females.

Emerging information from in-progress mortality experience analysis suggests that mortality has recently improved faster than estimated by projection scale AA. However, no standard tables have been published to replace the 1994 Uninsured Pensioners mortality table and projection scale AA for Canadian pension plan purposes. We expect that the mortality assumption will be changed in the first valuation of the plan prepared following publication of alternative mortality tables and projection scales, based on Canadian experience.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on actual membership data, which we believe is the most reliable source.

Spousal Age Difference

Actual spouse age is used where available, otherwise males are assumed to be 4 years older than their spouse.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

There are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. In particular, there are no additional benefits that would be immediately payable if the employer's business were discontinued on the valuation date. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. Therefore, no benefits payable on plan wind-up were excluded from our calculations.

Upon plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries Standards of Practice applicable for December 31, 2012.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2012 and December 30, 2013.*

However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2012 and December 30, 2013*, we have assumed that an appropriate proxy for estimating the cost of such purchase is using the yield on the long-term Government of Canada Real Return bonds.
Interest rate assumptions net of COLA used for lump sum transfers and annuity purchases take into consideration the 3% cap on pension increases provided by the plan provisions. We have

carried out a stochastic analysis in order to determine the additional net interest rate as a result of this 3% cap.

We have not included a provision for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum	70% of active members under age 55 and 50% of active members over age 55 elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	UP94 generational
Interest rate:	2.40% per year for 10 years, 3.60% per year thereafter
Interest rate net of COLA:	1.10% per year for 10 years, 1.50% thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	UP94 generational
Interest rate:	2.96% per year
Interest rate net of COLA:	0.60% per year
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan based on the eligibility requirements which have been met at the valuation date
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Termination expenses:	$200,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for expenses that may reasonably be expected to be paid by the pension fund under the postulated scenario between the wind-up date and the settlement date.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members retire and die consistent with the retirement and mortality rates used for the going concern valuation.
- Pensionable earnings, the *Income Tax Act* pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.
- Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis.

The solvency position is determined in accordance with the requirements of the Act.

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2012, provided by Canadian Utilities Ltd.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2012	31.12.2011
Active Members		
Number	28	33
Total pensionable earnings for the following year	$2,915,007	$3,452,193
Average pensionable earnings for the following year	$104,107	$103,794
Average years of pensionable service	24.9	24.7
Average age	54.2	53.9
Deferred Pensioners		
Number	5	5
Total annual pension	$53,017	$53,017
Average annual pension	$10,603	$10,603
Average age	51.9	50.9
Pensioners and Survivors		
Number	39	35
Total annual lifetime pension	$1,077,857	$833,232
Average annual lifetime pension	$27,637	$23,807
Average age	72.7	73.2

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Deferred Vested	Pensioners and Survivors	Total
Total at 31.12.2011	33	5	35	73
Transfers from Plan 1				
Transfers to Plan 1	(1)			(1)
Terminations:				
• Lump sums				
• Deferred pensions				
Deaths			(1)	(1)
Retirements	(4)		4	0
Survivors			1	1
Total at 31.12.2012	28	5	39	72

The distribution of the active members by age and pensionable service as at December 31, 2012 is summarized as follows:

	Years of Pensionable Service									
Age	**1-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35-39**	**40 +**	**Total**
< 25										
25 - 29										
30 - 34										
35 - 39										
40 - 44				1	3					4
45 - 49		1		1	1	1				4
50 - 54					2	1	3			6
55 - 59				1	2	3	2			8
60 - 64					2		1		1	4
65 - 69					1	1				2
70+										
Total	0	1	0	3	12	5	6	0	1	28

The distribution of the inactive members by age as at December 31, 2012 is summarized as follows:

	Deferred Pensioners		Pensioners and Survivors	
Age	**Number**	**Average Pension**	**Number**	**Average Pension**
< 45				
45 – 49	2	$4,440		
50 – 54	1	$26,351	1	$79,562
55 – 59	2	$8,893	2	$49,101
60 – 64			4	$38,841
65 – 69			9	$26,707
70 – 74			8	$25,095
75 – 79			4	$25,985
80 – 84			8	$19,086
85 – 89			3	$15,660
90 – 94				
95 – 99				
100 +				
Total	5	$10,603	39	$27,637

APPENDIX F

Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Canadian Utilities Ltd.. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2012. The following is a summary of the main provisions of the Plan in effect on December 31, 2012. This summary is not intended as a complete description of the Plan.

Background	The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC). Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Service under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets. Effective December 30, 2003, the Plan was extended to cover employees located in Ontario.
Eligibility for membership	The Plan is closed to new entrants. Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.
Employee Contributions	Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month following the member's 65th birthday. Early Retirement Date • If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.
Postponed Retirement	A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to his actual retirement.

Normal Retirement Pension	2% of annual final average earnings times years of pensionable service between January 2, 1962 and January 2, 1966; PLUS 1.4% of annual final average earnings up to the YMPE, times years of pensionable service after January 2, 1966; PLUS 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service after January 2, 1966.
Pensionable earnings	Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.
Early Retirement Pension	If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows: • if age and service sum to 90 years or more, no reduction applies; • otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:

Age at Retirement	Percentage
64	100
63	100
62	100
61	97
60	94
59	88
58	82
57	76
56	70
55	64

If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.

- In addition, female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable only until age 65. The bridge benefit is equal to the expected Canada Pension Plan benefit times the ratio of 36 divided by the number of months from retirement to age 65, provided that the ratio is never more than 1.

Maximum Pension	The Plan provides that the pension payable at the time of commencement must not exceed: • the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years) Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the ITA and Regulations.

Cost of Living Adjustments	The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid. The annual adjustment is granted to members who retired from active service.
Death Benefits	Pre-retirement: • If a member dies before becoming eligible for retirement, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. • If a member dies after becoming eligible for retirement, the member's spouse will receive the greater of: • a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value, and • an immediate pension equal to 60% of the pension to which the member would have been entitled had the member retired on their date of death. This pension will also receive future cost of living increases. • If a member dies after becoming eligible for retirement and there is no surviving spouse, the beneficiary will receive the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. Post retirement: • The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date • For employees with an eligible spouse, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.
Termination Benefits	A deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

APPENDIX G

Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2012 of the Retirement Plan For Employees of Canadian Utilities Limited and Participating Companies – Plan 2, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Canadian Utilities Ltd. engagement with the actuary described in section 2 of this report, particularly the requirement to include a margin of 2.10% after January 1, 2020 in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2012 were provided to the actuary and are reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarised in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2012.
- All events subsequent to December 31, 2012 that may have an impact on the Plan have been communicated to the actuary.

JUNE 28/13
Date

Signed

ERHARD KIEFER Carole Field
Name



Mercer (Canada) Limited
222 – 3rd Avenue SW
Suite 1200
Calgary, Alberta T2P 0B4
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The Yukon Electrical Company Limited
Breakdown of Pension Costs 2008-2015

	GRA Forecast 2008	Actual 2008	GRA Forecast 2009	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
Defined Contribution	-	-	-	-	87	113	106	112	114	118
Defined Benefit										
Current Service	441	428	467	466	368	377	401	410	403	403
Special Payments	-	-	-	-	205	211	406	415	408	408
	441	428	467	466	573	588	807	824	812	812
Pension Included in Schedule 5.1	441	428	467	466	660	701	913	936	926	930
Capitalized Pension	139	192	148	186	253	307	521	504	521	523
Total Pension	580	620	615	652	914	1,008	1,434	1,440	1,446	1,452
O&M %	76%	69%	76%	71%	72%	70%	64%	65%	64%	64%
Capitalized %	24%	31%	24%	29%	28%	30%	36%	35%	36%	36%
Total %	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

The Yukon Electrical Company Limited
Operations and Maintenance Expenses - Excluding Pension

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
1	**Production**								
2	62600 - Hydro Generation	87	116	105	100	141	299	379	413
3	64000 - Supervision and Engineering Diesel	53	54	55	54	58	54	56	58
4	64600 - Diesel Generation	332	395	441	546	401	473	660	671
5	82600 - Hydro Maintenance	47	31	19	60	103	47	48	49
6	84600 - Diesel Maintenance	1,002	970	864	966	1,131	1,159	1,182	1,206
7		1,521	1,566	1,483	1,725	1,833	2,031	2,325	2,396
8	**Distribution**								
9	87000 - Supervision	219	251	207	213	224	259	268	277
10	87100 - Brushing	322	326	349	277	534	395	404	412
11	87200 - Vehicle Depreciation	(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
12	87300 - Maintenance	1,251	1,566	1,593	1,629	1,705	1,768	1,821	1,912
13	87310 - Service to Outside Parties	70	83	64	90	101	103	105	107
14	87400 - Underground Line Maintenance	96	111	87	81	182	150	155	177
15	87500 - Meter and Meter Testing	151	113	85	94	105	84	87	90
16	87700 - Transformer Repair and Replacement	29	11	35	46	105	71	73	78
17	87800 - Street Light Maintenance	161	156	159	151	167	177	182	194
18		2,203	2,477	2,427	2,419	2,954	2,823	2,907	3,056
19	**General**								
20	88400 - Communication	8	17	9	10	15	12	13	13
21	88800 - Maintenance Company-Owned Houses	32	11	17	16	16	17	17	18
22	88900 - Maintenance Warehouse and Office	108	113	122	115	146	129	131	134
23		148	141	149	140	177	158	161	164
24	**Public Information**								
25	70100 - Public Information Administration	85	70	42	32	25	24	25	26
26	70200 - General Public Information	17	49	56	69	97	109	113	116
27		102	119	98	101	122	134	138	142
28	**Customer Accounting**								
29	71000 - Supervision	27	49	36	29	44	44	46	48
30	71100 - Customer Applications and Service Orders	326	410	365	359	373	406	438	468
31	71200 - Meter Reading	495	508	482	413	419	492	507	449
32	71300 - Customer Billing and Accounting	549	685	669	678	664	717	734	758
33	71400 - Revenue Collections	189	160	142	145	149	190	197	203
34	71500 - Collection of Delinquent Accounts	120	89	105	96	102	118	122	126
35	71800 - Provision for Uncollectible Accounts	36	34	43	36	36	36	36	36
36		1,741	1,934	1,843	1,757	1,786	2,004	2,079	2,088
37	**Administration and General**								
38	72100 - Administrative	1,453	1,446	1,552	1,692	1,921	2,171	2,318	2,315
39	72200 - Administrative Corporate	27	149	184	71	196	135	137	140
40	72300 - Insurance	207	228	215	244	245	262	202	138
41	72400 - Injuries & Damages	75	97	86	86	86	124	124	125
42	72500 - Employee Expenses	220	226	244	239	232	262	267	274
43	72600 - Training and Safety	288	377	363	345	390	407	419	435
44	72700 - Relocation	108	51	213	204	65	158	161	168
45	72800 - Miscellaneous General	3	-	-	-	-	-	-	-
46	72900 - Audit/Legal Fees & Special Studies	69	198	109	76	140	131	154	137
47		2,450	2,771	2,965	2,956	3,274	3,650	3,783	3,731
48									
49	**Total Operations and Maintenance Expenses - Excluding Pension**	8,165	9,008	8,965	9,098	10,146	10,799	11,393	11,577
	Total Pension Expense	428	466	660	701	913	936	926	930
	Total Operations and Maintenance Expenses - Including Pension	8,593	9,474	9,625	9,799	11,059	11,735	12,319	12,507

YUB-YECL-7

Reference: Discontinuance of Third Party Distribution Line (Property Insurance), YECL Application, page 5-5, YECL Application, Schedule 5-1

Yukon Electrical is proposing to discontinue purchased third party distribution line (property) insurance at the end of the 2013/2014 insurance period, July 1, 2014. On a go forward basis, insurable losses during construction or operations, if and when they occur, would be charged to the Reserve for Injuries and Damages.

The Board requires more details regarding YECL's plan.

Request:

(a) Please describe YECL's current RFID policy.

(b) Please explain how the proposed change will affect YECL's RFID policy and practices (e.g. will appropriations increase?).

Response:

(a) Yukon Electrical seeks to obtain insurance coverage except in cases where the exposure risk is minimal or the cost of the insurance is prohibitively high. In the case of an insured loss, amounts charged to the RFID would include the deductible portion of insured losses as well as any portion of the claim not paid by the insurance company. In the case of an uninsured loss where coverage was not obtained or was not available as a result of very high-risk exposure, the entire amount of the loss would be charged to the RFID. Please also refer to Section 8 Attachment 1 of Yukon Electrical's Application.

(b) The proposed change will not change Yukon Electrical's RFID policy. Yukon Electrical believes that the cost of the third party distribution line insurance, approximately $127,000 per year, is high for the amount of coverage provided, which is a limit of $1.5 million with a $1.0 million deductible. Additionally, there have not been any claims on the third party distribution line (property) insurance policy for the past 20 years.

YUB-YECL-18

Reference: Inflation forecasts and key assumptions table, YECL Application, page 1-7

For non-labour costs, an inflation rate of 1.9% has been applied for 2013 based on 50% of forecast Yukon inflation. For 2014 and 2015, no forecast of Yukon inflation was available so inflation rates of 2.0% and 2.1%, respectively, were applied based on 50% of forecast Alberta inflation and 50% of forecast British Columbia inflation.

The Board wants better understand YECL's non-labour inflation forecast and the methodology YECL used to come up with it

Request:

(a) Please provide the raw data that YECL used to determine the non-labour inflation rates used in this application.

(b) Please explain why YECL used a methodology that weights half of the non-labour inflation rate on Alberta inflation.

(c) Please explain why British Columbia inflation is the best proxy for Yukon inflation. Are there no forecasts for any other jurisdictions that are more representative of economic activity in the Yukon than British Columbia? Does YECL have historical evidence that supports using the British Columbia inflation rate?

Response:

(a) Please refer to YUB-YECL-18(a) Attachment 1.

(b) Yukon Electrical is using this methodology because it was the methodology directed to be used by the Board in Board Order 2009-2.

Use of Alberta inflation is reasonable as Yukon Electrical purchases a significant amount of goods and services from Alberta:

- Yukon Electrical's parent company ATCO Electric operates in Alberta and services received by Yukon Electrical by its parent company are therefore Alberta based;

- Yukon Electrical purchases many of its specialty line materials from Alberta; and

- Transportation services typically come from or through Alberta.

(c) Yukon Electrical was directed in Board Order 2009-2 to tie its non-labour inflation rate to two jurisdictions using a 50/50 weighting. As no forecast was available for the Yukon for 2014 or 2015, British Columbia was chosen as it was the closest jurisdiction to the Yukon. Other than British Columbia being a neighbouring jurisdiction to the Yukon with goods and services flowing up into Yukon, Yukon Electrical does not have historical evidence that supports the use the British Columbia rate.

The Yukon Electrical Company Limited
Forecast of Other Inflation 2013-2015

	2013 Forecast	2014 Forecast	2015 Forecast
Alberta CPI			
Bank of Montreal (Mar 1/13)	1.3	2.0	
CIBC World Markets (Jan 31/13)	1.1	2.4	
Conference Board of Canada (Feb 22, 2013)	1.8	2.2	
Global Insight (Feb 13/13)	1.9	2.1	2.2
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	2.4	2.4	
Alta Gov't Budget 2013 (Mar 8, 2013)	1.8	1.8	1.8
Average	**1.7**	**2.1**	**2.0**
Yukon CPI			
Yukon Gov't (Yukon Econ Development, Feb 5, 2013)	**2.0**		
British Columbia CPI			
Bank of Montreal (Mar 1/13)	1.1		
CIBC World Markets (Jan 31/13)	1.7		
Conference Board of Canada (Feb 22, 2013)	0.6	1.9	2.2
Global Insight (Feb 13/13)	1.0	1.9	2.0
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	0.6	1.9	2.2
BC Gov't Budget 2012 (Feb 19, 2013)	1.5	2	2.1
Average	**1.1**	**1.9**	**2.1**
Yukon Electrical Other Inflation Forecast	**1.9**	**2.0**	**2.1**

YUB-YECL-19

Reference: Inflation forecasts, YECL Application, page 1-7

A vacancy rate of 3.4% (approximately 2 FTEs) has been applied to all labour expenses for the 2013-2015 test periods. This is based on a five-year historical average which Yukon Electrical believes to be reasonable and is consistent with the methodology approved in Board Order 2009-2.

The Board seeks clarification regarding YECL's vacancy rate calculation.

Request:

(a) Please provide the raw data that YECL used to determine the vacancy rate.

(b) Please provide the calculations/steps YECL used to come up with the 3.4% vacancy rate.

Response:

(a) Please refer to YUB-YECL-19(a) Attachment 1.

(b) Yukon Electrical used the actual data from the previous 5 years of FTEs to determine a forecast vacancy rate. Please refer to YUB-YECL-19(a) Attachment 1 for the calculation used to come up with the 3.4% vacancy rate.

The Yukon Electrical Company Limited
2013-2015 General Rate Application
Calculation of Vacancy Rate

	Full-time Equivalents				
	Actual	**Forecast**	**+/-**	**Vacancies**	**%**
2008	52.85	54.76	(1.91)	1.91	3.5%
2009	55.51	55.76	(0.25)	0.25	0.4%
2010	54.64	55.43	(0.79)	0.79	1.4%
2011	54.47	57.08	(2.61)	2.61	4.6%
2012	56.36	60.52	(4.16)	4.16	6.9%
				1.94	3.4%

YUB-YECL-24

Reference: Demand-side management as it relates to revenue requirement, YECL Application, Business Case #30, page 1

Yukon Electrical, in partnership with Yukon Energy (YEC), has developed a five-year plan (2013-2018) to implement and measure demand-side management (DSM) programs for the Yukon that is being filed with this Application.

The Board seeks clarification on forecast costs related to DSM planning and implementation.

Request:

(a) Based on the quote above, please confirm that YECL anticipates implementing the DSM programs in 2013.

(b) On page 6 of Business Case #30, YECL submitted that Project Costs were $204,000, $143,000, $135,000, $522,000, $730,000 in 2011, 2012, 2013, 2014 and 2015 respectively. Please provide an update on how much YECL has actually spent on DSM to date since 2010. What were these costs for? Please delineate these costs.

(c) Have any costs related to DSM been expensed or gone into YECL's revenue requirement? If so, which accounts have been affected and by how much?

(d) Please provide the cost/benefit analysis for this business case.

Response:

(a) Yukon Electrical has been working with Yukon Energy collaboratively since 2011 to build a Demand Side Management plan for the Yukon. As part of the initial preparation for potential programs, a Conservation Potential Review (CPR) was completed. From that document, it was determined there was potential for electricity savings from DSM in the Yukon. The next stage involved developing a Program Portfolio, an Implementation Plan and an Evaluation, Measurement and Verification Plan. The utilities are now in the process of preparing for an anticipated public launch of DSM programs in late Q2 of 2014. This preparation

includes preparing internal systems and processes, engaging market actors, developing branding and marketing materials and developing an interactive customer website. This assumption is based on YUB approval of the programs as filed.

(b) Please refer to the *YECL-DSM Costs 2011-2015* spreadsheet, provided as YUB-YECL-24(b) Attachment 1, for details of Yukon Electrical costs related to DSM.

(c) Yes, costs related to DSM have gone into Yukon's Electrical revenue requirement. The DSM costs as outlined in Business Case #30 are included in capital additions for 2011-2015 and are included as additions to rate base beginning in 2013, on the assumption that the forecast costs will be approved as filed.

It is Yukon Electrical's intention to capitalize all costs associated with the DSM program. However, in preparing the responses to Information Requests, it was discovered that some costs had inadvertently been included in both Operations and Maintenance expenses and Capital. These amounts total $88,000 for 2013, $90,000 for 2014 and $92,000 for 2015. This duplication will be rectified by the removal of costs from O&M and this will be corrected and submitted as part of Yukon Electrical's compliance filing.

(d) The Yukon Electrical Business Case #30 is based on the *Yukon Five Year Demand Side Management Plan*. A cost/benefit analysis of the plan was completed and is based on the four standard cost effectiveness tests described in Appendix F of the *Yukon Five Year Demand Side Management Plan* included in the Application. The analysis of the cost/benefit ratios for each program as well as the total plan can be found in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management Plan* included in the Application.

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2015

Expenditure Type		Amount
DSM ADMINISTRATOR	$	93,000.00
STAFF TRAINING AND DEVELOPMENT		
PROJECTED COSTS FOR STAFF EDUCATION	$	17,000.00
DSM GENERAL SERVICE PROGRAM COSTS		
LIGHTING REDESIGN AND EQUIPMENT INCENTIVE	$	75,000.00
NEW CONSTRUCTION INCENTIVE	$	3,000.00
ENERGY STAR COMPUTER INCENTIVE	$	38,000.00
HIGH EFFICIENCY REFRIGERATION INCENTIVE	$	38,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	120,000.00
PROGRAM MANAGEMENT	$	79,000.00
	$	353,000.00
DSM RESIDENTIAL PROGRAM COSTS		
LED LIGHTING AND AUTOMOTIVE TIMERS	$	38,000.00
LOW COST ENERGY EFFICIENT PRODUCTS	$	78,000.00
CCHP AND GSHP INITIATIVE	$	15,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	65,000.00
PROGRAM MANAGEMENT	$	71,000.00
	$	267,000.00
FORECASTED 2015	$	730,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2014

Expenditure Type		Amount
DSM ADMINISTRATOR	$	93,000.00
STAFF TRAINING AND DEVELOPMENT		
PROJECTED COSTS FOR STAFF EDUCATION	$	17,000.00
DSM GENERAL SERVICE PROGRAM COSTS		
LIGHTING REDESIGN AND EQUIPMENT INCENTIVE	$	26,000.00
NEW CONSTRUCTION INCENTIVE	$	11,000.00
ENERGY STAR COMPUTER INCENTIVE	$	17,000.00
HIGH EFFICIENCY REFRIGERATION INCENTIVE	$	12,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	87,000.00
PROGRAM MANAGEMENT	$	44,000.00
	$	197,000.00
DSM RESIDENTIAL PROGRAM COSTS		
LED LIGHTING AND AUTOMOTIVE TIMERS	$	25,000.00
LOW COST ENERGY EFFICIENT PRODUCTS	$	74,000.00
CCHP AND GSHP INITIATIVE	$	7,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	57,000.00
PROGRAM MANAGEMENT	$	52,000.00
	$	215,000.00
FORECASTED 2014	$	522,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2013

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
ENERGY BLOCK FEASIBILITY	$	20,000.00
STAFF		
DSM ADMINISTRATOR	$	47,400.00
CONSULTATION		
FIRST NATION ENERGY SUMMIT	$	1,400.00
CONSULTANT SERVICES		
ICF MARBEK - PROGRAM IMPEMENTATION / EM&V PLANS	$	30,000.00
LAUNCH CONTRACTOR	$	20,000.00
	$	50,000.00
STAFF TRAINING AND DEVELOPMENT		
STAFF TRAINING AND DEVELOPMENT	$	15,000.00
LED STREET LIGHT JOINT PROJECT		
MATERIALS PURCHASED - LIGHTS	$	1,200.00
FORECASTED 2013	$	135,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2012

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
EM&V DATA PREPARATION	$	19,000.00
EDUCATION		
DOLLARS TO SENSE WORKSHOP	$	2,000.00
COMMUNICATION & ENGAGEMENT		
COMMUNICATION SERVICES	$	2,000.00
INCHARGE BRANDING	$	3,800.00
	$	5,800.00
CONSULTANT SERVICES		
PROGRAM DESIGN - ICF MARBEK	$	75,000.00
ONE CHANGE COMMUNITY ENGAGEMENT	$	41,000.00
	$	116,000.00
LED STREET LIGHT JOINT PROJECT		
MATERIALS PURCHASED - LIGHTS	$	2,000.00
TOTAL FOR 2012	$	144,800.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2011

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
ENERGY BLOCK FEASIBILITY	$	42,000.00
DATA REQUEST FOR CPR STUDY	$	3,000.00
	$	45,000.00
EDUCATION		
DOLLARS TO SENSE WORKSHOP	$	5,000.00
STAFF TRAINING AND DEVELOPMENT		
STAFF TRAINING AND DEVELOPMENT	$	4,000.00
CONSULTANT SERVICES		
CPR STUDY - ICF MARBEK	$	87,000.00
ONE CHANGE COMMUNITY ENGAGEMENT	$	63,000.00
	$	150,000.00
TOTAL FOR 2011	$	204,000.00

YUB-YECL-25

Reference: Electricity consumption in the Yukon, Yukon Five Year Demand Side Management Plan, Page 4

The CPR shows that in 2010, Yukon's residential sector consumed about 146,000 MWh of electricity

The Board requires the most up-to-date information available.

Request:

(a) Do YEC and YECL have an update of how much electricity is consumed in the Yukon for both the residential and commercial classes?

(b) Has the DSM program been implemented yet?

(c) To date, what activities have YEC and YECL conducted with regard to implementation of DSM? What has YECL done?

(d) What elasticity studies has YECL undertaken with respect to the demand for electricity? Please provide the results of those studies.

Response:

(a) The most up-to-date sales numbers as provided by each utility are detailed below:

Yukon Energy	2011 Residential – 12,834,145 kWh
	2011 Commercial – 21,537,664 kWh
	2012 Residential – 13,288,643 kWh
	2012 Commercial – 22,445,877 kWh
Yukon Electrical	2011 Residential – 141,696 MWh
	2011 Commercial – 150,591 MWh
	2011 Lights – 4,179 MWh
	2012 Residential – 150,350 MWh
	2012 Commercial – 159,562 MWh
	2012 Lights – 4,331 MWh

(b) No, DSM programs have not been implemented; however activities to prepare for program implementation have been on-going since 2011. As part of initial preparation for potential programs a Conservation Potential Review (CPR) was completed. From that document it was determined there was potential for electricity savings from DSM in the Yukon. The next stage involved developing a Program Portfolio, an Implementation Plan and an Evaluation, Measurement and Verification Plan. The utilities are now in the process of preparing for an anticipated public launch of DSM programs in late Q2 of 2014. This preparation includes preparing internal systems and processes, engaging market actors, developing branding and marketing materials and developing an interactive customer website. This assumption is based on a YUB approval of the programs as currently submitted.

(c) Yukon Energy and Yukon Electrical have cooperatively developed: the Conservation Potential Review for the Yukon; the Program Portfolio; the Program Implementation Plan; and the Evaluation, Measurement and Verification Plan. These plans are the foundation of public programs to be delivered to residential and commercial customers in order to meet the utilities' goal of 8.5 GWh of sustained electricity savings by the end of the five-year program cycle. Yukon Electrical has partnered with Yukon Energy on all of these initiatives.

(d) Yukon Electrical has not performed an analysis of the elasticity of demand for electricity due to the complexity of the study, lack of appropriate data and extensive amount of time it would take to perform such a study. However, based on a survey of studies reported for some jurisdictions in the U.S. by the Electric Power Research Institute titled, "Price Elasticity of Demand for Electricity: A Primer and Synthesis", dated January 2008, the elasticity of demand for general electricity use is estimated in the range of -0.2% to -0.6% in the short-run (1-5 years), and -0.7% to -1.4% in the long-run for residential customers, and between -0.2% to -0.7% in the short-run, and -0.8% to -1.3% in the long-run for commercial customers. Based on these numbers, for example, a 10% increase in the price of electricity of the residential rate class in the short-run would result in, everything else being constant, a 2% to 6% drop in electricity consumption by residential customers. For commercial customers, the same increase in price in the short-run would result in, everything else being constant, a 2% to 7% drop in electricity consumption. It should be noted that these elasticity estimates were all derived for jurisdictions with enabling technologies that provide for some sort of time-variable pricing (dynamic pricing) such as Time of Use, Critical Peak Pricing, or Real Time Pricing. As such, these customers are more aware and capable to react to price changes, if they choose to do so.

YUB-YECL-26

Reference: Public messaging and programing, Yukon Five Year Demand Side Management Plan, Page 8

The working group will jointly agree to develop: a program delivery process, electricity conservation public messaging, youth education programming, stakeholder consultation, evaluation, measurement, and verification of programs.

The Board wants to further understand how YEC and YECL plan on evaluating, measuring, and verifying program effectiveness

Request:

(a) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the electricity conservation public messaging is effective.

(b) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the youth education programming is effective.

(c) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the stakeholder consultations have been effective.

Response:

(a) The utilities will retain a third-party evaluation, measurement and verification (EM&V) contractor to look over the entire program portfolio and report on its effectiveness to the YUB. The utilities have prepared a set of performance indicators related to conservation public messaging. For example, a number of new market actors being engaged with, number of people attending classroom training, 1-to-10 scale level of satisfaction with the training on average, etc. These examples can be found on pages 32 and 33 of the *DSM Program Evaluation Measurement and Verification Plan*, provided as YUB-YECL-26(a) Attachment 1.

(b) The youth education component of the program is captured in the residential sector engagement, education and communication plan on page 95, section 4.4

of the *Yukon Five Year Demand Side Management Plan* included with the Application. This program is also subject to the EM&V plan.

(c) The utilities do not intend to explicitly ask the independent evaluators to comment on the effectiveness of the stakeholder consultations in a direct manner. It will be left to the independent evaluators to decide if they want to comment on them. As part of the process evaluation, evaluators will be provided with full access to the program documentation including, but not limited to: the Conservation Potential Review report and the market consultation / characterization documentation (reports, interview guides, protocols, consultations notes and so on).



Demand-Side Management (DSM) Program Portfolio for the Yukon

FINAL

Evaluation, Measurement and Verification Plan

Date: May 30, 2013

Submitted to:
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Yukon Electrical Company Limited

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1. Introduction

Yukon residents rely on electricity not only to live meaningful, healthy lives but also to support and strengthen the economy. Given the concerns over environmental implications including climate change, and the limited generating capacity in the Yukon, there is growing interest not only in how electricity is generated, transmitted and distributed but also how efficiently it is used at the customer's end. In the Yukon, as well as in a growing number of North American jurisdictions, how electricity is generated and used is being closely analyzed to find innovative ways of meeting individual and corporate energy service needs while minimizing pollution and the creation of greenhouse gases.

In response to these conditions, the Yukon Energy Corporation (YEC), Yukon Electrical Company Limited (YECL) and the Yukon Government collaboratively commissioned a comprehensive study of the opportunities for electricity demand-side management (DSM) within the Yukon. That study, entitled *Conservation and Demand Management Potential for the Yukon 2011*, was completed in January 2012 and revealed a significant cost-effective potential for electricity DSM in the Yukon.

Based on those findings, the YEC and YECL developed a suite of residential and commercial sector program offerings that will enhance the Yukon's electricity DSM program portfolio and provide incremental annual electricity savings of 9.3 GWh/yr by the fifth year of the program. The results of the development work are presented in a report, entitled *Demand-Side Management Program Portfolio for the Yukon* (also known as Program Design Document), which was completed in September 2012.

The final step in the DSM planning process involved the development of a program implementation plan (PIP) suitable for submission to the Yukon Utilities Board, together with an evaluation, monitoring and verification (EM&V) plan.

This report presents the recommended evaluation, measurement and verification (EM&V) plan for the Yukon DSM portfolio; it accompanies the PIP, which has been delivered under separate cover.

1.1 Objectives & Scope

The objectives of this EM&V plan are:

- To define an EM&V framework that will enable the Yukon Utility Board (YUB) to protect the interests of the ratepayers and maximize the value of DSM for all stakeholders, while also being compatible with the size of the Yukon market.
- To document the program's original theory and objectives for the evaluators to establish the basis for measuring success.
- To develop a high-level EM&V methodology and work plan to confirm the funding level, foresee data collection needs, and incorporate EM&V considerations into the regular program operations, accounting and management functions.
- To support the selection of program evaluators by providing a high-level description of the tasks and capabilities required.[1]

There are three audience groups for this report:

- The DSM program administration staff and the utility management committee.
- The Yukon Utility Board (YUB), the interveners, and other stakeholders.
- The selected evaluators.

The approach presented in this report is preliminary, and should be considered as a suite of options which, as a whole, represent EM&V best practice. The final evaluation scope will be determined through the stakeholder engagement process.

1.2 Report Presentation

The remainder of this report is organized and presented in the following sections:

- Section 2 introduces the recommended EM&V framework for electricity DSM in Yukon.
- Section 3 provides an overview of the Yukon DSM and defines a high-level approach, key milestones and deliverables, and a schedule for EM&V activities.
- Section 4 presents the description, program theory, management by objective (MBO) framework and methodological implications for each of the program elements within the DSM portfolio.
- Section 5 presents an approach, guidelines and criteria to select impartial and capable evaluators.

[1] The team developing this EM&V plan was also involved in the development of the program portfolio. Evaluators will be selected outside of the development team to avoid any conflict of interest. After being selected, the impartial evaluators will provide their expert opinion on the methodology and work plan, gather comments from relevant stakeholders, edit and finalize the EM&V plan.

2. EM&V Framework for DSM in Yukon

Section 2 sets out the recommended high-level characteristics of the DSM evaluation framework for the Yukon. The discussion is organized into the following sub sections:

- General approach
- Rationale for DSM evaluation
- Targets and performance indicators
- Level of rigor and funding
- Applicable evaluation best practices
- Roles and responsibilities
- Technical reference manual and deemed savings

2.1 General Approach

A sound evaluation framework should lay the ground for superior energy conservation policy planning and program management to increase the value of DSM for the Yukon ratepayers and society. The key is to balance:

- The Program's need for quick program performance feedback and for flexibility to adapt the DSM portfolio to changing market conditions.
- The expectation of the DSM program participants for excellent customer service from the Utilities which in many cases implies swift processing of a minimal amount of paperwork.
- The need of the regulator to ensure ratepayer monies are being used in an effective and efficient manner to achieve energy impacts.
- The need of the Yukon society for a self-improving DSM program portfolio, which monitors market feedback, and applies educated and evidence-based recommendations to improve the portfolio.

The recommended approach for the Yukon is a two-layer portfolio monitoring approach:

- **Internal Tracking and Performance Reporting:** DSM program administration staff will track a set of indicators as defined below. Indicators are monitored by diligently inputting data into a program tracking system (program database) and periodic reports are generated (quarterly, yearly) that compare actual results against targets. This will enable the program administrator, as applicable, to justify results, suggest corrective measures and update targets for the next period.
- **Third-Party Program Evaluation:** The Utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities as defined in this report. Third-party program evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. The program evaluators will retrieve the program database and documentation; check that program procedures and eligibility criteria were complied with by the administration staff; retrieve additional market data through consultation, surveys and other research methods; use advanced energy analytics to improve the accuracy and precision of the impact estimates; and provide constructive criticism of the DSM portfolio.

This EM&V plan focuses primarily on the second layer: *third-party program evaluation*. The tracking and performance reporting infrastructure and functions were described extensively in the Program Implementation Plan. This EM&V plan will refer to tracking when tracking data is needed for evaluation purposes.

The EM&V plan was built based on a 5-year DSM portfolio planning and operation cycle; thus with a 5-year impact evaluation reporting cycle. A 3- to 5-year cycle is standard practice in the industry because it maximizes the value of evaluation. A 5-year cycle was preferred as a means of constraining the EM&V costs. This recognizes the relatively small size of the Yukon DSM market and, consequently, the relatively small size of the DSM budget.

2.2 Rationale for DSM Evaluation

Evaluation is meant to improve DSM program performance such that it sustainably obtains incremental electricity and demand savings. The high-level objectives of DSM evaluation are:

- **Establishment of DSM as a credible and reliable resource:** DSM evaluation increases the accuracy and precision of the impact estimates (e.g. avoided kWh and kW) thus making DSM impact claims worthy of being compared with supply-side resources. The power system planners need to trust in DSM if they are to postpone or curtail supply-side investments on the basis of the DSM projections; actually postponing and curtailing these investments is key to realizing a large portion of the societal benefits of DSM.
- **Explanation of the performance of the programs:** Evaluation helps DSM administration staff interpret the tracking data, and explains why certain programs have under-performed or over-performed. Evaluators consult with several market actors to obtain insights on the reactions of the market to the DSM programs and to seek solutions.
- **Recommendations to adapt and improve programs:** Evaluators will use the results of their research and consultation in Yukon, as well as their experience with DSM in other jurisdictions, to make educated recommendations to adapt and improve the DSM portfolio. For example, those recommendations can include the identification of: subtle tune-ups of operating practices; promising new tactics; ineffective tactics; new DSM opportunities: exit strategies for specific program elements; and, changes in the delivery approach.
- **Accountability of the DSM program administrator:** Evaluators will have access to all of the program documentation including the CPR report, the market characterization reports, the PIP, the tracking database, communication materials, meeting minutes, performance reports, budget and planning, etc. They will identify issues, if any, with the approach to planning and taking programs to market, record keeping practices, data quality control procedures, the timeliness of the application processing, performance indicators, mid-course portfolio adjustments, and ultimately the DSM management and administration practices.

2.3 Targets and Performance Indicators

The utilities will aim to achieve total net electricity savings that are equal to or greater than the total amounts presented in the DSM portfolio projections, and at a total cost that is equal to or less than the total amount presented in the DSM budget (see the Program Design document). However, the utilities will have the flexibility to move targets and budgets between the DSM program elements to adapt to changing market conditions and early program results. Quarterly budgets will also be flexible as long as annual budgets are complied with.

The performance of the program will be measured through the following three sets of activities:

- The performance will be periodically monitored by the DSM administration staff by comparing *key performance indicators* (KPIs) with pre-established targets – that will include kW and kWh savings, or *impacts*.
- The KPIs will be validated by the evaluators by conducting a desk review of the program database and the program documentation, additional research activities, and advanced energy analytics.
- The evaluators will also establish and monitor additional indicators (*evaluation indicators*) to verify that the DSM portfolio is being delivered effectively and that it generates sustainable positive changes in the market.

The program activities will be tracked and performance will be reviewed according to the report and planning schedule presented the Program Implementation Plan (See Section 4.4).

Tracking – Key Performance Indicators

The program accounting system and internal tracking systems will report on the KPIs for each of the program elements of the DSM portfolio. The most important KPIs are listed below.

1. Number of transactions and number of business days of average processing time
2. Incentive disbursement cost
3. Program cost and administration cost
4. kWh and kW savings (gross)[2]
5. Number of transactions being verified on site (to be determined with the DSM administration staff at the preparation stage and then validated by the EM&V contractor)
6. Direct-engagement indicators (to be determined with the program staff at the preparation stage)
7. Indirect communications indicators (to be determined with the program staff at the preparation stage)

The targets for KPIs (1) to (5) above were set out in the projection tables presented in the Program Design Document. KPIs (6) to (8) will be established during program set up in collaboration with the core program staff.

In addition to the information required to track the KPIs above, the evaluators will designate a limited number of information items to be collected for EM&V purposes.

[2] The tracking system will report on net impact if a stipulated net-to-gross ratio is used.

All KPIs computed by the DSM accounting system and the tracking system(s) will be verified by evaluators. The evaluators will also validate the approach to on-site verification, and the information items being collected through the applications and forms for verification purposes.

Evaluation – Evaluation Indicators

In addition to the KPIs stated above, evaluation indicators will be established and documented through EM&V to test the effectiveness of the DSM portfolio delivery mechanisms.

Both the KPIs and the evaluation indicators and targets will be laid out in detail in a management-by-objective framework (MBO framework). The suggested MBO Framework is presented in Section 4.

2.4 Level of Rigor and Funding

The value of EM&V can also to be maximized through setting realistic expectations for the precision and accuracy of the impact estimates. The cost of evaluation grows exponentially as the level of rigor is set higher, and since the cost of DSM remains lower than supply-side options it is common to tolerate a wider margin of error.

One common approach is to set the level of EM&V funding and then establish what is achievable in terms of evaluation scope as well as accuracy and precision of expectations. This is the approach used in this EM&V plan.

Most industry standards suggest allocating 3 to 10% of total program funds to EM&V, where the higher end of the range is for (1) newer programs and (2) smaller programs. It is expected that the Utilities' new DSM programs will be small programs relative to most other jurisdictions. Thus, the Utilities expect to invest between 5 and 8% of the DSM budget in EM&V. The current EM&V plan reflects this level of funding.

The accuracy and precision are to be recommended by the evaluation contractors when bidding on the evaluation work. The level of rigor is to be differentiated by program element. The evaluators shall seek to allocate more resources to program elements that have yielded the highest impact (based on KPIs).

2.5 Applicable Evaluation Best Practices

The Utilities intend to follow the general principles of the California Evaluation Framework[3] and the California Evaluation Protocols (a.k.a. Evaluators' Protocols)[4] but at a level of rigor that is consistent with the size of the overall program.

The two reference books noted above are suggested for the Yukon because:

- The North-American DSM evaluation industry is familiar with them. Few evaluation references are more used than these two California documents; they are the result of extensive work by dozens of evaluation professionals to collect and consolidate EM&V methods and options that had been used successfully at the time. The selected evaluators will be at ease.

[3] **CPUC**, *California Evaluation Framework*, TechMarket Works, USA, 2004, [ONLINE] As seen on March 25, 2013, URL: http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf
[4] **CPUC**, *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals*, USA, 2006, [ONLINE] As seen on March 25, 2013, URL: http://www.calmac.org/events/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf

- They are comprehensive reference books with a wealth of methodological options from the most basic to the highest level of rigor, for many types of evaluation, and for a vast array of program designs. They are versatile and flexible.
- Both handbooks refer to the International Performance Measurement and Verification Protocol (IPMVP)[5] for larger projects that justify investing in actual field measurements, as required.
- In addition to project-level M&V, these handbooks accommodate one or many approaches to carrying out impact estimates: billing analysis, sampling and the use of statistics, deemed savings, and advanced engineering methods.

Most of the EM&V methods that will be put forward will need to be defined and/or positioned relative to the recommended approaches suggested in the Evaluation Framework and the Evaluators' Protocols.

Evaluators will be expected to make an educated use of the California handbooks. They will be able to suggest alternate approaches and methodologies, as appropriate.

2.6 Roles and Responsibilities

The Utilities intend to employ one third-party evaluation contractor for both the General Service Program and the Residential Program.[6]

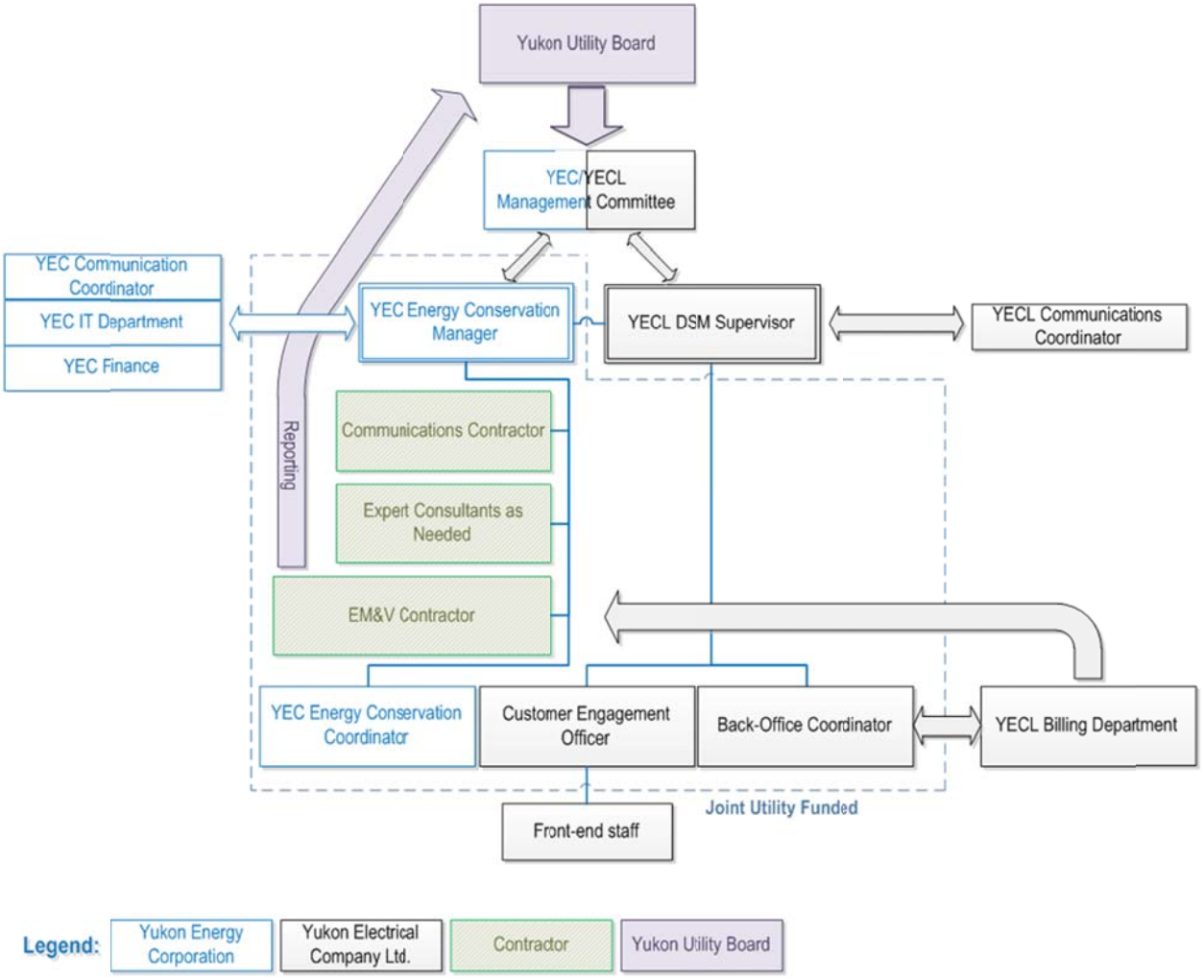
The value of EM&V will be maximized through a practical division of responsibilities between DSM administration staff and the EM&V contractor. For example, certain measurement or site-visit activities can be carried out and documented by the administration staff as part of regular tracking at a much lower cost than if they were to be performed by the EM&V contractor. In this case, the logs and documentation would be reviewed by the contractor.

[5] **EVO**, *International Performance Measurement and Verification Protocol, Volume I, 2012*, USA 2012, [ONLINE] As seen on March 25, 2013, URL: http://www.evo-world.org

[6] It is desirable to retain one EM&V contractor for both the General Service Program and the Residential Program because the total budget envelope for evaluation is relatively small and bundling will allow for economies of scale. In addition, DSM will benefit from the EM&V contractor having flexibility to assign resources among the program elements based on actual impact and/or expenses to date in order to maximize the value of evaluation.

Exhibit 1 outlines the anticipated organization of key roles once the program is fully launched and is in full operation. An explanatory note is presented in tabular format following the chart that presents the tracking and EM&V responsibilities for the key players involved in the operation of the DSM portfolio, and how they relate to the Management Committee and the YUB.

Exhibit 1: Organization Chart during Full Program Operation



Position	Payroll	Role/Responsibility with Regard to EM&V
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Develop the initial EM&V plan – to be finalized through consultation with the EM&V Contractor, YECL DSM Supervisor, the YEC/YECL Management Committee, and the YUB.

Position	Payroll	Role/Responsibility with Regard to EM&V
		• Prepare reports and documents to be filed with the YUB under the supervision of YEC/YECL Management Committee (most likely made of extracts from the aforementioned reports, budgets and plans). • Procurement of the services of the EM&V contractors, and expert consultants when needed. • Coordination between the positions or resources shown in Exhibit 1. • Update the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the EM&V Contractors' deliverables. • Monitor the customer engagement KPIs • Work jointly with the YECL DSM Supervisor to update and approve of the engagement plan updates by the YECL Customer Engagement Officer.
YEC/YECL Management Committee	YEC or YECL	• Review and comment on the reports, budgets and plans drafted by the YEC Energy Conservation Manager and the YECL DSM Supervisor. • Provide directions to the YEC Energy Conservation Manager and the YECL DSM Supervisor on the reports and documents to be filed with the YUB, review and approve these documents and file them. • Work with the YEC Energy Conservation Manager and YECL DSM Supervisor to address comments from the YUB and interveners.
YEC Energy Conservation Coordinator	YEC	• Maintain the tracking system, control the quality of the data inputted into the system. • Extract reports from the accounting system and the tracking system for the YEC Energy Conservation Manager (KPIs, charts, etc.). • Supports the YEC Energy Conservation Manager with the development of quarterly or annual reports. • Support the YEC Energy Conservation Manager with EM&V, with selecting the EM&V Contractor, and with the coordination with the EM&V Contractor. • Support the YEC Energy Conservation Manager with selecting technical experts as needed, and with the coordination with these experts. • Provide technical assistance to all inCharge personnel as needed.
YECL Back-Office Coordinator	YECL	• Handles applications and completion forms. • Feeds the tracking system with transactional information as required in the operation manual. • Proceeds with in-situ verification of a few transactions (spot-check verifications that are going to be selected randomly).
YECL Billing Department	YECL	• Send utility billing data to EM&V Contractor as needed and when needed, directly to the contractor, and under a confidentiality agreement with the contractor.
YEC Finance	YEC	• Support the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS).
YEC Information Technology (IT) Department	YEC	• Support the YEC Energy Conservation Coordinator with tracking system maintenance. • Collaborate with the Communication Contractor to monitor traffic on the inCharge website.

Position	Payroll	Role/Responsibility with Regard to EM&V
Communications Contractor	Contractor for YEC	• Record keeping on the engagement and communication activities to be determined during the set-up stage.
YECL DSM Supervisor	YECL	• Jointly accountable with YEC Energy Conservation Manager for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Review and approve the detailed work plan when updated by the YEC Energy Conservation Manager. • QC/QA of all of the communication materials being generated by the YEC Energy Conservation Manager and the Communications Contractor. • Record keeping on the engagement and communication activities to be determined during the set-up stage.
YECL Communications Coordinator	YECL	• Support YECL DSM Supervisor as needed.
Customer Engagement Officer	YECL	• Log the events or actions in order to compute the engagement KPIs. • Log program transactions (for example: program applications) that YECL channels to YECL Back-Office Coordinator with time stamps. • Track incentive reimbursements coming from YEC; and make sure there are no discrepancies between the tracking information of YECL and that of YEC. • Regarding the above, investigate any discrepancy as soon as possible. • Gather data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS.
Yukon Utility Board (YUB)	YUB	• Look out for the interests of the rate payers and authorize the use of rate payers' monies on DSM. • As such, the YUB requires DSM to be implemented in a rigorous, cost-effective and optimal manner. All documents filed with them should demonstrate these attributes. • They achieve the above by asking questions and making comments on the reporting and planning documents filed with them; in particular the EM&V reports.
Evaluation, Measurement and Verification (EM&V) Contractor[7]	Contractor for YEC	• Finalize the evaluation, measurement and verification plan. o Review the tracking system and procedures, and recommend changes to maximize the value of EM&V. o Establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, and so on (Refer to Section 2.7 for more details). o Collect some additional market baseline information if and as needed.

[7] Refer to Section 4 for more details.

Position	Payroll	Role/Responsibility with Regard to EM&V
		• Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6). o Do some quality control/quality assurance of the program impacts as computed by the tracking system. • Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.
Expert Consultants	Contrac-tors for YEC	• Support inCharge staff as required, to update the prescriptive incentive lists (both the incentive level and the eligible products). • Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).

Readers can refer to Section 4 of the PIP for additional details about the roles and responsibilities of the above positions in the context of program launch and operation, including their roles and responsibilities beyond EM&V.

2.7 Technical Reference Manual and Deemed Savings

The Utilities envision working with the EM&V contractor to build and verify a technical reference manual (TRM)[8]. The TRM will then be used to track program performance and evaluate program impacts.

A TRM is a repository of all of the project inputs and assumptions (PIAs) used to compute the program impact of *prescriptive conservation measures*. Most of the "smaller" energy conservation measures in the program portfolio will be treated as prescriptive conservation measures (for example the residential LED lamps, automotive heater timer, and ENERGY STAR Computers).

Each PIA usually includes the following items:

- Data to estimate impact and compute cost-effectiveness tests: Annual electricity savings, peak demand savings, measure incremental cost, and measure lifetime.
- Other natural resource savings and interactive effects: for example water and fossil fuels.
- Justification of all of the above including: algorithms, engineering equations and/or engineering model, inputs and assumptions, detailed cost information, and sources.
- Logs of the changes in the PIAs and justifications.
- Estimates of expected program attribution percentage (stipulated net-to-gross-ratio or NTG ratio).

The use of PIAs to estimate program impact is often referred to as the "deemed savings approach". The deemed savings approach will be recommended when the savings and rebate per prescriptive measure will not justify investing in field measurements, when a sampling approach will be cost-prohibitive given the level of funding of evaluation in absolute terms, and when savings cannot be established through utility billing data analysis. For example, this will be the case for residential LED lamps, automotive heater timers, and ENERGY STAR Computers.

[8] Note: A preliminary version *of the TRM was created as part of the CPR and the program design report.*

The creation, verification and continuous update of a TRM is an organized approach to the use of deemed-savings estimates. Every month new evaluation reports are being filed in North America and some of these evaluations are performed in larger jurisdictions with more resources and – in some cases – they include actual field measurements, surveying or sophisticated billing analysis to back the assumptions. The TRM is a tool to ensure continuous improvement of the deem-savings estimates; with time, the DSM staff and evaluators will gather and aggregate better assumptions based on new evaluation results in other North-American jurisdictions, as relevant.

3. Overview of EM&V for the Proposed DSM Portfolio

This section introduces the general approach to evaluation for the proposed DSM portfolio during the next 5-year operation window. This introduction is organized into the following sub sections:

- Evaluation scope
- Main evaluation work packages
- Evaluation schedule

3.1 Evaluation Scope

Evaluation will encompass all of the programs and programs elements that are recommended for the Utilities' initial DSM portfolio. The EM&V contractor will be expected to allocate resources among the elements of the DSM portfolio to maximize the overall value of the evaluation work. Consequently, they will need to be provided with a broad description of the DSM portfolio, projections and budget, as provided below.

DSM Design Principles and Portfolio Structure

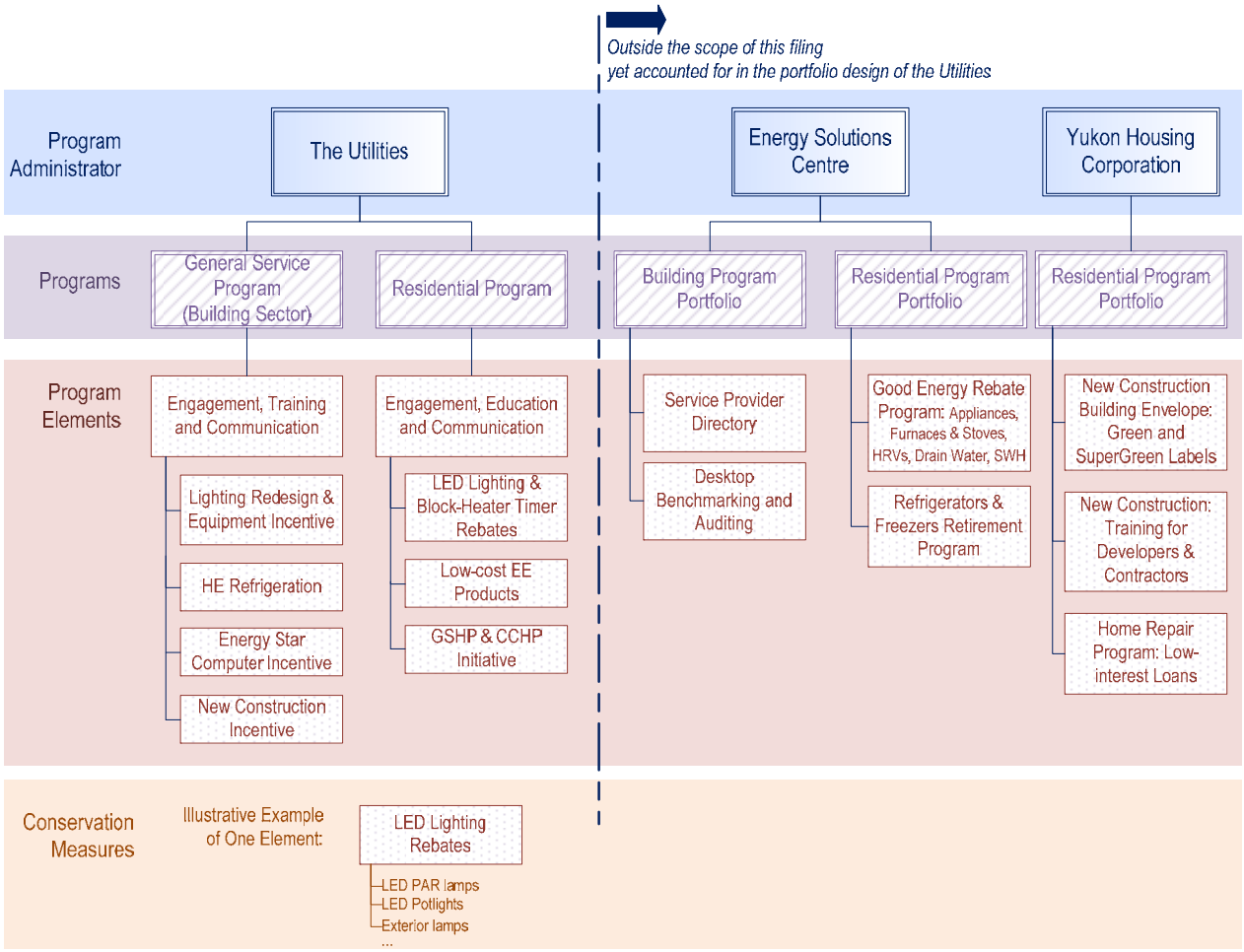
Two broad solutions-based programs are presented, each with multiple program elements: the General Service Program and the Residential Program. The objective was to offer customers a broad suite of options to meet their electricity management needs, rather than forcing customers to sort through a variety of individual programs.

Several specific design guidelines were applied to the programs presented. Those that are relevant to the evaluators are:

- The Utilities should retain design flexibility to enable program implementers to adjust specific designs as dictated by customer response and evaluation results.
- The Utilities should ensure that the program offerings complement existing energy initiatives in the Yukon and minimize duplication or potential customer confusion. To this end, there has been extensive collaboration with local entities such as the Energy Solutions Centre, Yukon Housing, City of Whitehorse and others.

Exhibit 2 presents the proposed overall portfolio of the Utilities' electricity programs. It also shows the current complementary energy programs offered by the Energy Solutions Centre and Yukon Housing.

Exhibit 2: Portfolio Structure



The portfolio in Exhibit 2 is the starting point for the Utilities. It is anticipated that timely adjustments will be made in response to feedback from customers and trade allies as well as the performance of individual programs. These changes will be documented through the internal performance reports, and annual budgeting and planning documentation.

DSM Portfolio Projections and Budget

Exhibit 3 and Exhibit 4 present an overview of the portfolio budget, impact projections, and Benefit/Cost results as anticipated before the preparation and launch stage.

The EM&V contractor should allocate evaluation resources among the program elements in a manner that is commensurate with the expected DSM expenditures and impacts for each. This EM&V plan already accounts for the importance of the program elements relative to each other based on budget and projections; however, the EM&V contractor will be provided with flexibility to further refine the methodology and resource allocation to reflect actual accounting reports, tracking results and KPIs.

The results are presented for the proposed five-year period by individual program element, program, as well as for the portfolio as a whole. The results are also organized within two scenarios:

- **Without Government Buildings:** This assumes that government owned buildings are not eligible to participate in the programs. Government buildings include buildings from all levels of government: federal, territorial, first nation, and municipal.
- **With Government Buildings[9]:** This assumes that all Yukon buildings are eligible to participate in the programs.

In each case, the results presented include:

- **Net Savings – Lifetime MWh:** These are the lifetime electricity savings attributed to (only) the measures implemented in the year shown and are inclusive of transmission and distribution losses.
- **Net Savings – Annual MWh**: These are the electricity savings that would occur in the milestone year shown due to the impacts of the measures implemented to date under the program. They are inclusive of T&D losses.
- **Utility Expenditure**: These show the associated incentive and non-incentive program costs that would be incurred in each milestone year.
- **Benefit/Cost Ratios:** These are the results of the standard benefit-cost tests. The acronyms refer to: the TRC – Total resource cost test; the PAC – Program administrator cost test; the PC – Participant cost test; and the RIM – Rate impact measure test. Seasoned evaluators will be accustomed to them. Explanations on these were provided in the Program Design Document. The definitions that were used are compliant with the 2001 California Standard Practice Manual.[10]

Notes to support the interpretation of Exhibit 3 and Exhibit 4:

- There is no incremental cost to the Participant to purchase an ENERGY STAR computer.
- In case of inconsistencies, the Exhibit in the Program Design Report should prevail.

[9] For example, the DSM plan could include a caveat that some level(s) of government will not participate in DSM programs that are funded from rate-base.

[10] **CPUC**, *California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects*, October 2001, USA, [ONLINE] as seen on March 26, 2013, URL: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

Exhibit 3: Portfolio Results Excluding Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)						Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - excluding gov. buildings	Lifetime MWh:	0	2,476	6,240	7,132	7,132	22,981	Incentive:	$4	$96	$213	$239	$222	$773	1.1	2.8	2.5	0.9
	Annual MWh:	0	333	1,140	2,062	2,985	N/A	Non-Incen.:	$77	$78	$81	$85	$111	$432				
	Coincident kW:	0	79	269	486	703	N/A	Total:	$81	$175	$294	$323	$333	$1,205				
New Construction Incentive - excluding gov. buildings	Lifetime MWh:	0	306	1,377	2,142	2,448	6,273	Incentive:	$0	$4	$19	$30	$34	$87	4.2	4.9	6.3	1.0
	Annual MWh:	0	15	84	191	314	N/A	Non-Incen.:	$4	$31	$5	$31	$12	$82				
	Coincident kW:	0	3	19	44	72	N/A	Total:	$4	$35	$24	$60	$46	$169				
High-Efficiency Refrigeration Incentive - excluding gov. buildings	Lifetime MWh:	0	0	6,301	0	6,301	12,602	Incentive:	$0	$0	$122	$0	$122	$243	3.2	4.5	4.2	1.0
	Annual MWh:	0	0	630	630	1,260	N/A	Non-Incen.:	$10	$91	$17	$54	$42	$214				
	Coincident kW:	0	0	72	72	143	N/A	Total:	$10	$91	$138	$54	$163	$458				
Energy Star Computer - excluding gov. buildings	Lifetime MWh:	32	205	335	0	0	573	Incentive:	$2	$10	$17	$0	$0	$29	1.8	1.2	*	0.6
	Annual MWh:	8	59	143	143	135	N/A	Non-Incen.:	$26	$12	$15	$2	$5	$60				
	Coincident kW:	1	11	26	26	24	N/A	Total:	$28	$22	$32	$2	$5	$89				
Engagement, Education and Communication - excluding gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$167	$251	$224	$175	$217	$1,034				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$167	$251	$224	$175	$217	$1,034				
Total General Service Program excl. gov. buildings	Lifetime MWh:	32	2,988	14,253	9,274	15,881	42,428	Incentive:	$5	$111	$371	$268	$377	$1,132	1.3	2.1	3.2	0.8
	Annual MWh:	8	408	1,997	3,027	4,693	N/A	Non-Incen.:	$284	$463	$341	$346	$387	$1,822				
	Coincident kW:	1	93	385	627	942	N/A	Total:	$290	$574	$712	$615	$764	$2,954				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,747	10,294	21,319	17,243	23,504	75,108	Incentive:	$56	$219	$474	$380	$477	$1,606	1.3	2.1	2.9	0.8
	Annual MWh:	221	1,167	3,287	4,887	7,098	N/A	Non-Incen.:	$706	$824	$670	$703	$815	$3,718				
	Coincident kW:	77	363	845	1,290	1,800	N/A	Total:	$762	$1,043	$1,145	$1,083	$1,292	$5,325				

Exhibit 4: Portfolio Results Including Government Buildings

Program Elements	Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - including gov. buildings	Lifetime MWh:	0	4,314	10,711	12,241	12,241	39,506	Incentive:	$6	$135	$294	$327	$299	$1,062	1.2	3.8	2.4	0.9
	Annual MWh:	0	507	1,731	3,128	4,526	N/A	Non-Incen.:	$81	$77	$66	$72	$127	$425				
	Coincident kW:	0	127	432	781	1,129	N/A	Total:	$88	$213	$360	$400	$427	$1,487				
New Construction Incentive - including gov. buildings	Lifetime MWh:	0	471	2,118	3,295	3,766	9,651	Incentive:	$0	$6	$25	$39	$45	$115	4.7	6.1	6.7	1.0
	Annual MWh:	0	24	129	294	483	N/A	Non-Incen.:	$28	$9	$6	$33	$16	$93				
	Coincident kW:	0	5	30	67	110	N/A	Total:	$28	$15	$32	$72	$61	$208				
High-Efficiency Refrigeration Incentive - including gov. buildings	Lifetime MWh:	0	0	7,580	0	7,580	15,161	Incentive:	$0	$0	$132	$0	$132	$263	3.2	4.3	4.6	1.0
	Annual MWh:	0	0	694	694	1,388	N/A	Non-Incen.:	$36	$100	$19	$86	$49	$290				
	Coincident kW:	0	0	80	80	161	N/A	Total:	$36	$100	$151	$86	$180	$553				
Energy Star Computer - including gov. buildings	Lifetime MWh:	107	681	1,111	0	0	1,899	Incentive:	$6	$35	$57	$0	$0	$98	2.0	1.3	*	0.6
	Annual MWh:	27	197	475	475	448	N/A	Non-Incen.:	$36	$52	$74	$6	$17	$185				
	Coincident kW:	5	35	85	85	80	N/A	Total:	$41	$88	$131	$6	$17	$284				
Engagement, Education and Communication - including gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$202	$290	$255	$200	$252	$1,199				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$202	$290	$255	$200	$252	$1,199				
Total General Service Program incl. gov. buildings	Lifetime MWh:	107	5,466	21,520	15,536	23,587	66,217	Incentive:	$12	$176	$508	$367	$476	$1,538	1.3	2.5	3.2	0.8
	Annual MWh:	27	728	3,029	4,591	6,845	N/A	Non-Incen.:	$383	$529	$420	$398	$461	$2,192				
	Coincident kW:	5	167	627	1,013	1,480	N/A	Total:	$395	$705	$928	$765	$937	$3,730				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,822	12,772	28,586	23,505	31,210	98,896	Incentive:	$63	$284	$612	$478	$576	$2,012	1.4	2.3	2.9	0.8
	Annual MWh:	240	1,487	4,318	6,451	9,250	N/A	Non-Incen.:	$762	$957	$782	$787	$904	$4,191				
	Coincident kW:	81	438	1,087	1,677	2,338	N/A	Total:	$824	$1,240	$1,393	$1,266	$1,480	$6,203				

3.2. Main Evaluation Work Packages

Section 3.2 provides a description of the types of evaluation required, summarizes the experimental approach anticipated, and then lists of all the physical deliverables that will be part of the EM&V work.

The approach presented in Section 3.2 is preliminary, and should be considered as a suite of options which, as a whole, represent EM&V best practice.

The general approach is based on four main work packages:

- **Finalization of the EM&V Plan** – to be initiated between the fourth and the sixth quarter after the start of the program operation window (that is: between Y1-Q4 and Y2-Q2).
- **Process Evaluation Study** (EM&V Study #1) – to be initiated two to six quarters after the first DSM incentive transaction (that is: sometime between Y2-Q2 and Y3-Q2 if the first-transaction milestones are passed according to the plan).
- **Impact Evaluation Study** (EM&V Study #2) – to be initiated five to eight quarters before the end of the program window (that is: between Y4-Q1 and Y4-Q4 based on a 5-year operation window).
- **Project-Level M&V Studies** – the evaluators will be convened to perform certain project-level M&V planning, analysis and reporting tasks as needed many times thorough the program operation window.

The four work packages are described below. They are also laid out in a Gantt chart in Section 3.3 Evaluation Schedule.

Finalization of the EM&V Plan

The final evaluation scope will be determined through initial collaboration with the EM&V contractor once selected, and consultation with the YEC/YECL management committee and YUB. It is expected that the contractor will be selected and under a contract between the fourth or sixth quarter of program operation. Finalizing the EM&V plan should take about three months to complete.

Finalizing the EM&V Plan encompasses the following activities:

- Review, edit, and adapt the EM&V plan based on the outcomes of the activities below.
- Collect and review all program documentation so far: the CPR report, market characterization reports, program design document, PIP, early reports from the preparation and launch stage, transactional and operational materials, communication materials and meeting minutes.
- Carry out a few in-depth interviews with YEC and YECL staff, as needed.
- Narrow down the methodological options or suggest other innovative methods to maximize value of EM&V, while in compliance with the California Evaluation Framework.
- Compute the detailed EM&V budget using the actual professional rates of the contractor staff, based on the final recommended approach and based on the rate inflation forecast.
- Identify gaps in the market characterization reports, recommend and carry out some early baseline data collection tasks, as needed.

- Check the logic models for soundness and suggest improvements, based on the result of the activity and above and as needed.
- Review, edit and adapt the TRM based on a desk review of the TRM, on a comparison with other North-American TRMs and on a jurisdictional scan of relevant evaluation reports.
- Establish stipulated net-to-gross ratios for all program elements and measures based on a jurisdictional scan of relevant evaluation reports, and experience.
- Review the transactional and operational materials (application and internal forms), and the tracking system and identify: (i) superfluous information items, and (ii) missing information items that will be required for EM&V purpose. Suggest corrective actions as needed.
- Review and edit the protocols regarding site verification of conservation measures under the responsibility of the administration staff.
- Use the existing program theory and logic models to assess whether the theory is plausible and suggest improvements.

The final EM&V plan should include the following items either in the body of the document or as part of the appendix:

- A verified TRM that will be used to generate KPIs and performance reports for all program elements.
- A revised list of incentive levels for all prescriptive measures.
- Stipulated NTG ratios for all program elements accounting for the above.
- A new version of evaluation indicators and baseline levels (as required) to assess the effectiveness of the delivery mechanism.
- A list of corrective actions on the transactional materials and tracking system, as needed.
- A formal approval of the site-verification protocols and approach to documenting the verifications.

Process Evaluation Study

The following paragraphs provide a description of the type of evaluation required and summarize the experimental approach anticipated, the major deliverables and special methods sought from the evaluation contractor.

The process evaluation study (EM&V Study #1) will be initiated two to six quarters after the first DSM incentive transaction. It should take about six months to complete.

The purpose of a process evaluation is to identify corrective actions to improve the program uptake, impact and cost-effectiveness. The rationale behind carrying out the process evaluation early after the launch of the program is to achieve the benefits of the corrective actions before the end of the current program operation window.

Evaluators will be asked to suggest corrective actions applicable to the incentive levels, communication strategy, transactional infrastructure, tracking and performance reporting, site verifications, delivery approach and institutional framework, and program management practices. Evaluators can go as far as suggesting pulling some program elements out of the market if these elements are deemed ineffective.

Evaluators will suggest corrective actions in light of:

- A consultation with relevant market actors (e.g.: participants, non-participants, supply-side actors and relevant stakeholders) through surveying, interviewing and/or others.
- The desk review of the program database content, accounting reports, communication tactics and materials, performance reports, and site verification documentation.

EM&V Study #1 will also include a few impact-evaluation and cost-effectiveness evaluation components.

- Evaluators will work on updating and tuning the TRM based on any new information that might have come up since the finalization of the EM&V plan – like new relevant evaluation reports from other jurisdictions, new information collected through program tracking, observations made during site verification, or market insights gained during market consultation.
- Evaluators will work on carrying out the ex-post cost-effectiveness tests based on the most recent program data. Evaluators are encouraged to use the same modeling tool used by the administration staff to generate the annual performance report, modify it as required, and validate it to make sure that the reports being filed with the YUB by the administration staff are sound.

Generic Process Evaluation Research Questions: The following are generic research questions that evaluators will be asked to answer as part of the process evaluation study. An answer will be asked for each of the program elements that are laid out in Section 4. Where specific questions or nuances to the generic questions below are needed for each program element, they are laid out in Section 4.

1. Is the program design (theory, strategy, tactics and incentive level) effective at realizing savings (kWh and kW)?
2. Are the program management and operational and transactional infrastructure effective and efficient at delivering the tactics, mitigating risks (fraud and the like), supporting tracking and evaluation, and improving customer satisfaction?
3. Is the program communication strategy effective and efficient at generating uptake in the program element?
4. Is the approach to estimating the impacts as part of program tracking rigorous and effective at establishing DSM as a credible and reliable resource?
5. How much of the impact should be attributed to the program administrator – early estimate for program tracking purposes? (that is: an early stipulated NTG ratios)
6. Is the approach to carrying out the ex-post cost-effectiveness tests sound and effective at supporting DSM planning decisions?

When answering all of the questions above, evaluators will seek to recommend solutions to the issues that might be uncovered and improvements to make the DSM portfolio more effective and efficient.

The main deliverable of EM&V Study #1 will be a Process Evaluation Report at the culmination of the study. The report should include the following items either in the body of the document or as part of the appendix:

- A list of corrective actions, a justification for each, and advice on how to roll these out (who? when? how? how much?).
- A new version of verified TRM.

- A new version of stipulated NTG ratios.
- Verified KPIs for program operation up to a month before the delivery of the report;
- Cost-effectiveness test results based on actual program data for program operation up to a month before the delivery of the report.
- A list of recommendations applicable to EM&V Study #2 and an updated EM&V plan accounting for these recommendations.

Impact Evaluation Study

The impact evaluation study (EM&V Study #2) will mostly consist of impact evaluation research questions. Specific research questions will be laid out for each project element in Section 4. Study #2 will be initiated five to eight quarters before the end of the program window. It is expected that the study will take about twelve months to complete; a first draft should be presented to the YEC/YECL management committee three months before the end of the program operation window (about Y5-Q3) and the final report should be filed with the YUB three months after the end of the program window at the most (about Y6-Q1).

The purpose of impact evaluation is to increase the level of precision and accuracy of the impact estimates filed with the YUB. Evaluators will increase the accuracy and precision of the impact estimates through:

- Additional data collection activities and impact evaluation methods as presented in Section 4.
- Updating and tuning the TRM based on any new information that might have come up since the culmination of EM&V Study #1. The approach will be similar to the one used during Study #1.

Evaluators will generate verified KPIs for program operation up to the end of the program operation window, and then they will carry out the ex-post cost-effectiveness tests based on these KPIs.

Evaluators will observe the changes in the market – whether induced by the DSM portfolio or otherwise – through consultation with relevant market actors through surveying, interviewing and/or other means. It is expected that the same evaluation contractors will have cumulated sufficient relevant market observations to provide an insightful and educated opinion regarding the evolution of the Yukon market and the implications on the current and future DSM portfolio. The evaluators will have accumulated these observations through accessing the market characterization reports as well as research and consultation in Yukon as part of the finalization of the EM&V plan, the process evaluation study, the project-level M&V work, and the impact evaluation study.

Evaluators will be expected to provide an opinion on whether program elements became irrelevant or whether new opportunities have arisen. Program evaluators will be able to make high-level recommendations on the future of DSM in Yukon that will be used to design the next generation of programs.

Generic Impact Evaluation Research Questions: The following are generic research questions that evaluators will be asked to answer as part of the impact evaluation study. Specific questions for each of the program elements are laid out in Section 4.

1. How much of the impact claimed by the program administrator has actually been realized? (i.e. the realization ratio)
2. How much of the impact should be attributed to the program administrator – what is the final estimate? (i.e. the final stipulated NTG)

3. What are the actual ex-post results of the cost-effectiveness tests?
4. Have the program operation standards and procedures been complied with and properly documented?
5. What are the implications of the evolution of the Yukon market on the program design and delivery mechanisms?

When answering all of the questions above, evaluators will seek to make high-level recommendations to make the next generation of Yukon DSM programs more effective and efficient.

The main deliverable of EM&V Study #2 will be an Impact Evaluation Report at the culmination of the study. The report should include the following items either in the body of the document or as part of the appendix:

- A new version of verified TRM.
- A new version of stipulated NTG ratios.
- A realization ratio for each of the program elements.
- Verified KPIs for program operation up to the end of the program operation window based on the above.
- Cost-effectiveness test results based on actual program data for program operation up to the end of the program operation window.
- Evaluation indicators, comparison with baseline levels, comparison with targets and conclusions on the effectiveness of the DSM portfolio at transforming the market.
- Recommendations on the next generation of programs in Yukon including but not limited to: programs that became (or are about to become) irrelevant, ineffective or counter-productive; exit strategies or overhaul of existing program elements; significant changes in the delivery approach; and new DSM opportunities to be investigated.

The evaluators will provide a justification for each of the recommendations they make.

Project-Level M&V Studies

The *Project-Level M&V Studies* work package consist of a series of call ups for the evaluators to perform project-level M&V activities including the planning of project-level M&V, the interpretation and analysis of measurements, and drafting of M&V reports. The outcomes of this work are to be integrated in EM&V Study #2; however the program administrators should be able to trigger these activities independently from the course of Study #1 and #2.

Projects that will need M&V are:

- **General Service high-efficiency refrigeration projects in food retail stores and ice rinks.** These projects are planned to occur in two waves: a first wave is planned to start around Y2-Q2, construction is to end on Y3-Q3, and the post-retrofit measurement period – expected to last for one year – is to end around Y4-Q3. The second wave will start on Y4-Q2 then follow a similar schedule. The completion of the M&V work for that second wave falls outside of the program window.
- **Residential innovative heating projects.** These projects are planned to be implemented between Y1-Q4 and Y3-Q2, and thus the post-retrofit measurement period – expected to last for one year – is to end between Y2-Q4 and Y3-Q3.

The notional schedules presented above depend on the willingness of participants and market stakeholders to carry out these projects and thus the administrator will need flexibility from the evaluators on the timeline.

In addition to impact-evaluation purposes, project-level M&V work has the following objectives:

- Feedback verified information on project savings to the market through case studies and other communication tactics to boost the uptake of the programs. – It is assumed that actual M&V results will reinforce the case studies by making them more credible.
- Validate the viability of technologies in the Yukon, identify risks, and provide insights that will be fed in the planning and decision whether to roll out a full-scale residential innovative heating incentive program.

The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days.

The specific M&V tasks for each project include:

- Collect pre-retrofit utility bills and information about the project and building.
- Draft a project-specific M&V plan.
- Collect post-retrofit utility-bills, as well as routine and non-routine adjustment parameters.
- Supervise or carry out at least one site visit and document field observations.
- Carry out M&V analysis in accordance with the plan.
- Draft an M&V report.

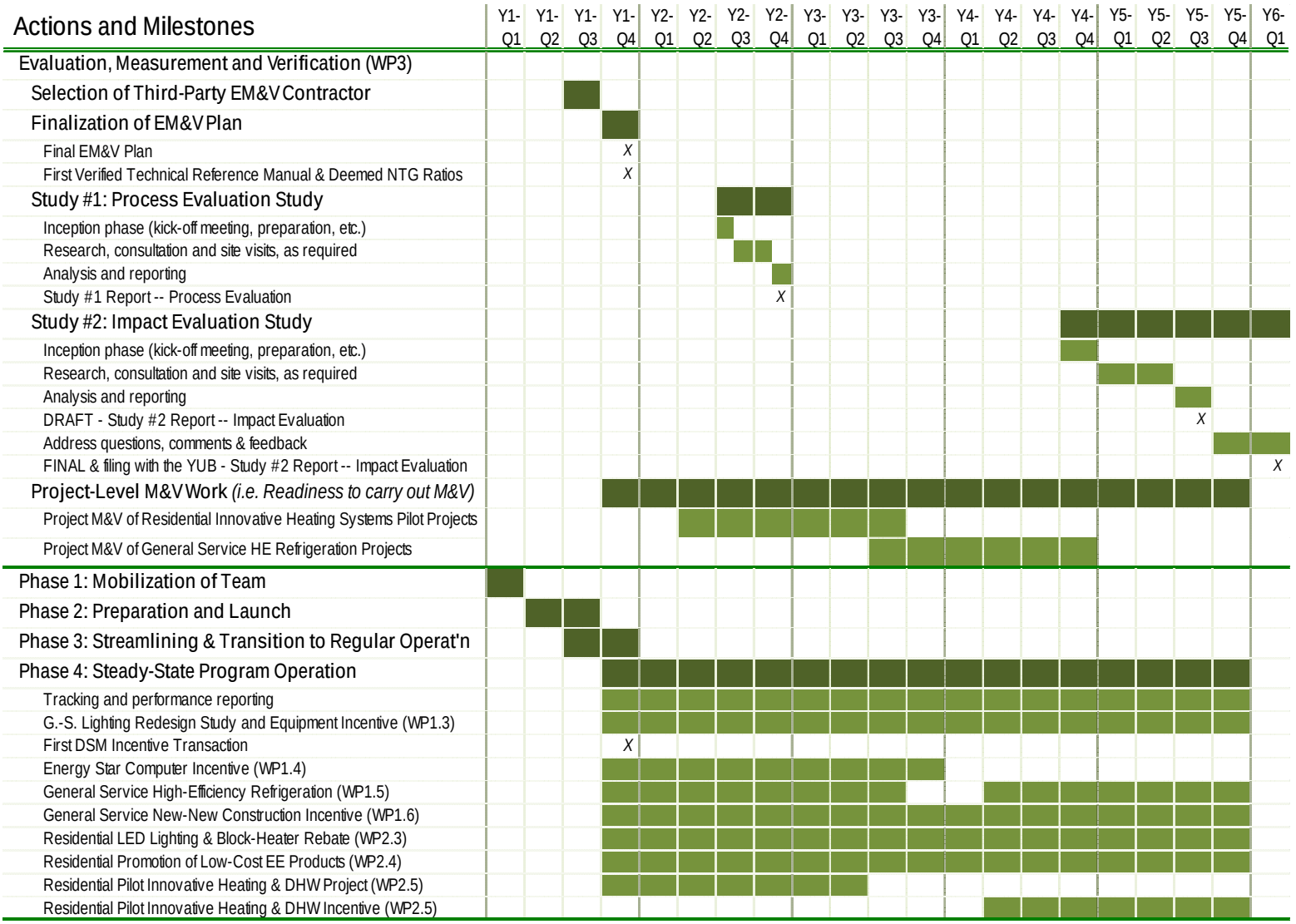
The deliverables for each project include: an M&V plan, and a final M&V report.

Evaluators will be able to suggest other methodological options and approaches they deem relevant, as long as the suggested approaches align with the IPMVP methodological options.

3.3 Evaluation Schedule

Exhibit 5 shows a schedule for EM&V as part of the 5-year program operation window. The EM&V activities, deliverables and milestones are stacked up above a high-level schedule of the program implementation and operations.

Exhibit 5: High-Level Gantt Chart of the Evaluation, Measurement and Verification Work



The schedule for EM&V shown in Exhibit 5 is approximate. The DSM administration will have the flexibility to shuffle the work packages in the 5-year operation window depending on the status of the DSM portfolio; for example the *Finalization of the EM&V Plan* could be postponed by up to two quarters, *Study #1* could be postponed by up to three quarters and/or *Study #2* could be started up to three quarters earlier. However, Y6-Q1 for the filing of the impact evaluation report is a hard deadline.

4. Program-Specific Evaluation Implications

This section provides a description of the specific EM&V requirements for each of the seven program elements that, together, make up the Yukon DSM program portfolio. The discussion is organized and presented by program element, as outlined below.

- General Service Program, which consists of the following four program elements:
  - Lighting Redesign and Equipment Incentive
  - High Efficiency Refrigeration Program
  - Energy Star Computer Incentive
  - New Construction Incentive
- Residential Program, which consists of the following three program elements:
  - LED Lighting and Automotive Heater Timer Rebate
  - Promotion of Low-Cost Energy Efficient Products
  - GSHP and CCHP Initiative

For each program element noted above, the discussion addresses the following areas:

- **Program Description Summary**

  It is standard practice to provide a program description summary as part of EM&V plans. This enables the evaluators to appreciate the program type and the nature of the conservation measures/projects being promoted and, therefore, to more easily establish their evaluation approach. The program theory is also essential to developing indicators that will enable performance-based management and planning.

- **Evaluation Considerations**

  The evaluation considerations are specific to each of the seven program elements. They build on the general approach presented in Section 3. All of the seven program elements will concurrently be subjected to a process evaluation (Study #1), and then an impact evaluation (Study #2). The discussion of evaluation considerations for each program element is further organized into the following areas:
  - Management-by-objective framework
  - Evaluation research questions
  - Suggested evaluation methods and level of rigor

4.1 General Service Lighting Redesign and Equipment Incentive

4.1.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers to have their lighting systems retrofitted. The total incentive will be the sum of three layers:

- Lighting redesign incentive
- Custom lighting incentive
- Prescriptive LED lighting incentive

The Utilities will pay an incentive to building owners/managers to have a lighting redesign conducted in their building. The purpose of the lighting redesign will be to design the optimal lighting system in term of visual comfort, ease of maintenance, and electricity savings considering the existing spaces, windows and fixtures. The incentive for the redesign work will be determined using a dollar-per-square foot rate. The lighting designers will be required to develop designs that meet minimum power density thresholds.

The custom lighting incentive includes a base incentive for the equipment and installation determined using a dollar per kilowatt-hour of annual savings rate. This approach provides flexibility in choice of lighting technologies and also allows contractors and designers to be innovative.

For the prescriptive LED incentive layer, the Utilities will add a flat amount of money per unit for LED products selected from a prescriptive list of eligible products.

Building owners/managers will be able to combine the custom incentive layer, the LED prescriptive incentive layer, and the lighting redesign incentive layer to best suit their needs and to generate a larger incentive for LED technologies: the initial-cost hurdle is higher for the LED technologies and the Utilities have a goal of accelerating market penetration of these products. The prescriptive list of eligible LED products will be consistent with that used in the Residential Program.

Eligible Measures

The proposed incentive levels as well as archetype projects are presented in Exhibit 6 to Exhibit 9.

Exhibit 6: Archetype Lighting Conservation Projects – Custom Incentive Layers for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM91	Lighting Redesign Study	0.00 kWh/ft2	.00000 kW/ft2	110%	$1.20/ft2	16.0 yr	$0.40/ft2	11,759 ft2
ECM80	Typical Lighting Project in	1.99 kWh/ft2	.00060 kW/ft2	95%	$1.40/ft2	15.4 yr	$0.16/ft2	15,000 ft2
ECM81	Typical Lighting Project in Existing Bldg - Food Retail	4.85 kWh/ft2	.00092 kW/ft2	95%	$2.30/ft2	15.4 yr	$0.39/ft2	30,000 ft2
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail	3.64 kWh/ft2	.00072 kW/ft2	95%	$1.90/ft2	15.4 yr	$0.29/ft2	10,000 ft2
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel	1.84 kWh/ft2	.00036 kW/ft2	95%	$2.10/ft2	11.5 yr	$0.15/ft2	20,000 ft2
ECM86	Typical Lighting Project in Existing Bldg - Restaurant	6.65 kWh/ft2	.00140 kW/ft2	95%	$3.10/ft2	13.0 yr	$0.53/ft2	4,000 ft2
ECM87	Typical Lighting Project in Existing Bldg - Recreation	1.79 kWh/ft2	.00043 kW/ft2	95%	$1.90/ft2	15.7 yr	$0.14/ft2	25,000 ft2
ECM88	Typical Lighting Project in Existing Bldg - Warehouse	1.85 kWh/ft2	.00045 kW/ft2	95%	$2.00/ft2	15.7 yr	$0.15/ft2	30,000 ft2

Exhibit 7: Prescriptive LED Incentive Layer for Non-Government Buildings

ID	Measure Short Name	Level of Incentive
ECM92	Commercial 12W LED A19 Bulb	$18.00/unit
ECM93	Commercial 8W LED A19 Bulb	$12.00/unit
ECM94	Commercial LED MR16 Bulbs	$10.00/unit
ECM95	Commercial LED PAR30 Bulbs	$20.00/unit
ECM96	Commercial LED PAR38 Bulbs	$20.00/unit
ECM97	Commercial Spot or task lighting	$10.00/unit

Exhibit 8: Archetype Lighting Conservation Projects – Custom Incentive Layer for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM912	Gov. Lighting Redesign Study	0.00 kWh/ft2	.00000 kW/ft2	100%	$1.20/ft2	20.0 yr	$0.24/ft2	26,209 ft2
ECM802	Gov. Typical Lighting Project in	1.99 kWh/ft2	.00060 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.10/ft2	15,000 ft2
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health	2.45 kWh/ft2	.00035 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.12/ft2	95,000 ft2
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education	1.15 kWh/ft2	.00042 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.06/ft2	33,000 ft2
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation	1.79 kWh/ft2	.00043 kW/ft2	95%	$1.90/ft2	20.0 yr	$0.09/ft2	25,000 ft2
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse	1.85 kWh/ft2	.00045 kW/ft2	95%	$2.00/ft2	20.0 yr	$0.09/ft2	30,000 ft2

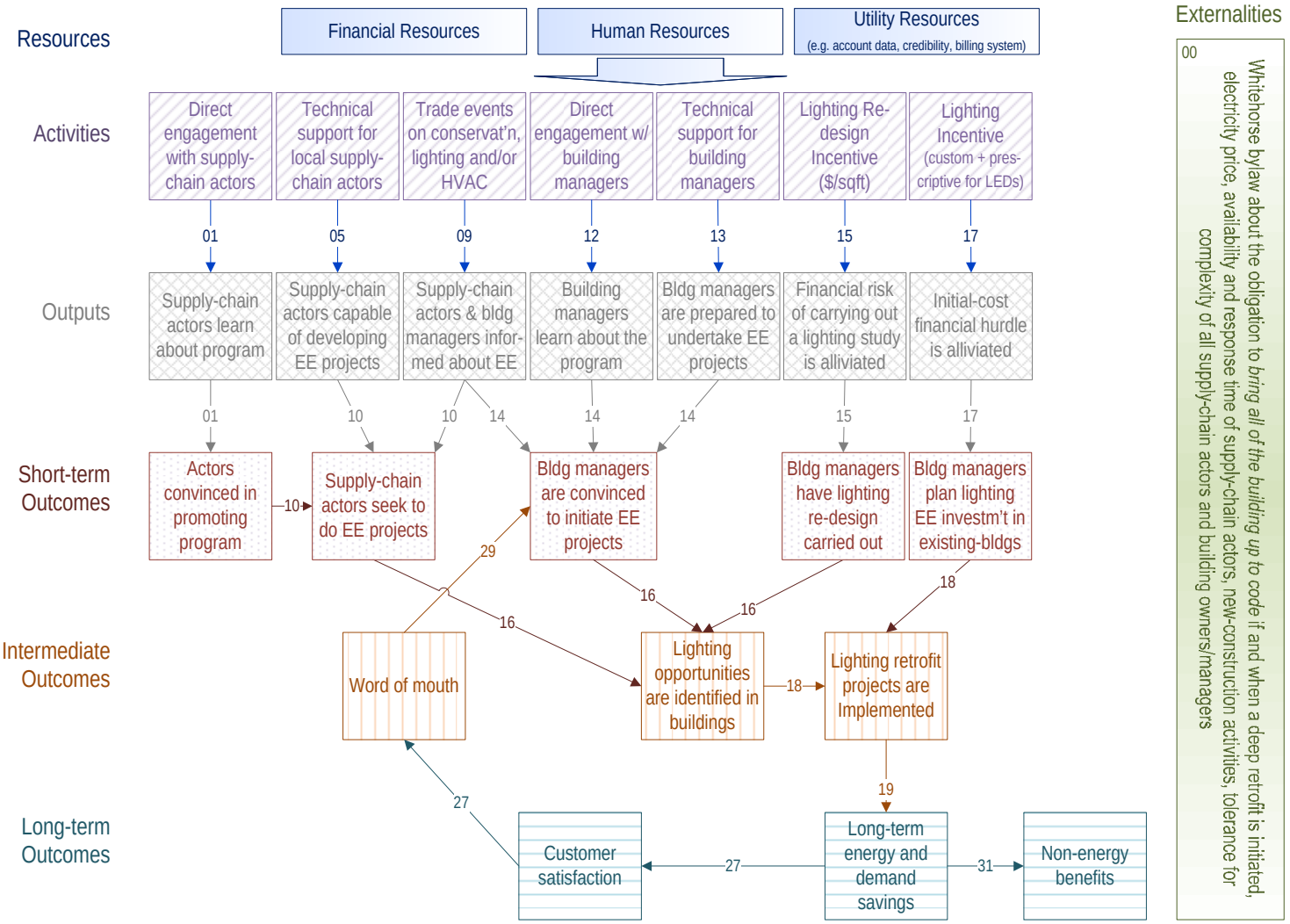
Exhibit 9: Prescriptive LED Incentive Layer for Government Buildings

ID	Measure Short Name	Level of Incentive
ECM922	Gov. Commercial 12W LED A19 Bulb	$10.80/unit
ECM932	Gov. Commercial 8W LED A19 Bulb	$7.20/unit
ECM942	Gov. Commercial LED MR16 Bulbs	$6.00/unit
ECM952	Gov. Commercial LED PAR30 Bulbs	$12.00/unit
ECM962	Gov. Commercial LED PAR38 Bulbs	$12.00/unit
ECM972	Gov. Commercial Spot or task lighting	$6.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below. The offering logic model is annotated from top (resource allocation) to bottom (intended impacts) in the table following the chart.

Exhibit 10: Logic Model for the General Service Lighting Redesign and Equipment Incentive



Link #	Narrative
00	Externalities: The program effectiveness and impact will be influenced by the following externalities: Whitehorse bylaws on the obligation to bring all of the buildings up to code if and when deep retrofits are initiated, the price of electricity, the availability and response time of supply-chain actors, new-construction activities, and tolerance for complexity of all supply-chain actors and building owners/managers. The program administrator should monitor these externalities and adapt the implementation approach as necessary.
01	Direct engagement with supply-chain actors: The Utilities will carry out direct engagement with electrical distributors, lighting designers, electrical contractors, as well as with HVAC contractors, HVAC designers, control designers and architects through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and engage with supply-chain actors so that they promote them.

Link #	Narrative
05	Technical support for local supply-chain actors: The Utilities will offer technical support to the supply-chain actors in two different forms: (1) hands-on training on the program tools, forms and procedures; on advanced electricity efficiency lighting design; and on the business aspects of electricity efficiency: energy audits, business cases, energy performance contracting, and electricity efficiency financing. (2) The Utilities will act as a broker to procure technical expertise from highly specialized lighting experts recruited throughout North America upon request from the local actors. In addition, the Utilities will disseminate information on recommended lighting equipment (brand-neutral, to the extent possible) in the form of printed brochures, newsletters or web content.
09	Trade events on conservation, lighting and/or HVAC: The Utilities propose to support any form of trade organizations or trade events by sponsoring and attending trade events that gather local building owners/managers and/or supply-chain actors. The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories, and share their lessons learned.
10	Supply-side actors will actively seek to develop projects because they were engaged with by the Utilities, because they were trained and are capable of offering electricity-efficiency services, and because they were provided with networking opportunities with potential clients (building owners/managers) at trade events.
12	Direct engagement with building managers: The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings; and through public relations activities like media advisories sent to the local newspapers and radio, web content, and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
13	Technical support for building managers: The Utilities will offer customized technical support to building owners/managers to help them to initiate projects. The Utilities could include support to plan investment in assets, and to identify in which buildings to develop projects; support to make optimal decisions on implementation and procurement approach, and support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities, because they were provided with technical support to decide where to start and how to do it, and because they networked with supply-side actors, perhaps at the trade events supported by the Utilities.
15	Lighting redesign incentive: The Utilities will pay an incentive to building owner/managers to have a lighting redesign study conducted in their building. The purpose of the lighting redesign study will be to design an optimized lighting system in term of visual comfort, ease of maintenance, and electricity savings, considering the existing spaces, windows and fixtures. The incentive will reduce the financial risk of investing in a pre-investment study, and will reduce the initial-cost hurdle of doing business with designers. The building managers will have lighting redesign studies carried out.
16	Electricity-efficient lighting opportunities are identified in the building because the supply-chain actors were seeking to develop new lighting projects, because building owners/managers agreed to initiate an electricity efficiency project and because the financial risk of carrying out a redesign study was alleviated.
17	Lighting equipment incentive: The Utilities will pay an incentive to building owners/managers to have their lighting systems retrofitted. This incentive will include a custom incentive layer and a prescriptive LED incentive layer. The custom incentive allows for flexibility in lighting technologies as well as the use of occupancy control, dimming and day lighting, etc. It pushes distributors, contractors and designers to be innovative. The purpose of the prescriptive LED incentive layer is to increase the level of incentive when LED technologies are used because the initial-cost hurdle is higher for LED technologies than for other technologies; and because LED lighting is a technology for which the Utilities would like to accelerate market penetration.
18	Electricity-efficient lighting retrofit projects are implemented because electricity-efficient lighting opportunities were identified and because the equipment and installation initial-cost financial hurdle was alleviated.
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings.

Link #	Narrative
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry; perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and have increased property value.

4.1.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 10 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 11. Performance indicators should be reviewed by the EM&V contractor to validate the theory.

Explanatory notes on Exhibit 11 and MBO frameworks in sections 4.2 to 4.7 are provided below:

- **Part A & Part B.** The MBO framework was divided into two parts:
  - Part A is for the key performance indicators (KPIs) that will be monitored by the administration staff through operations, application and incentive processing, and minimal record keeping of communications and engagement work. Then these KPI results are to be validated by the evaluators.
  - Part B is for the evaluation of market performance indicators. These indicators will be established by evaluators through surveying, consultation, research and analysis as part of the two main evaluation studies: process evaluation and impact evaluation.

- **Components of the MBO Framework:**
  - *Link # and Narrative* refers to the Logic Model for the program element. See Exhibit 10.
  - *Performance Indicators* are the metrics used as KPIs, the evaluation indicator.
  - *Sources* will tell the evaluators where the data needed to compute the indicators must come from. In Part A, most of this data is internal to the program administration: it will be contained either in the program documentation, tracking system or logs of communication and engagement activities.
  - Targets for Year 1 to 5: Goals the actual indicators will be compared against. Those presented below are preliminary and will be validated as laid out below.

- **Starting Point and Later Stages.** The MBO framework presented below is a starting point. After the delivery of this EM&V plan, it will go through various stages of validation and transformation: These stages are:
  - During startup, the launch team will review it and adapt it to its preferences and based on the record-keeping standards that are agreed on. This is why, in many cases, performance indicators are referred to as "*Suggested indicators or KPIs*".

- During the finalization of the EM&V plan, the launch team and evaluators will review the MBO framework and goals, and then sign off on it.
- During operation and on an annual basis, the program administration staff will be able to change the MBO framework and targets based on early results, challenges and market conditions. Whenever changes will be made, the administration staff will document the justifications for the evaluators to review.
- With each program evaluation report, the evaluators will present the MBO Framework with actual indicators against the latest targets.

- **Sum of Section 4.1 to 4.7.** Section 4.1 to 4.7 will present a MBO framework for each of the seven program elements in the portfolio. Such a breakdown creates an appearance of redundancies and overlaps on paper when in many cases the indicators will be the same. The selected evaluation contractor will harmonize and streamline these when collapsing the program-specific research topics and methods into one coherent work plan.

Exhibit 11: Management-by-Objective Framework for the Lighting Redesign and Equipment Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Direct engagement with supply-chain actors	Suggested KPI(s):	Direct engagement & communication logs					
		# of new actors being engaged with for the 1st time		10	25	5	5	5
		# of actors solicited for market intel & updates		10	35	35	35	35
		# of actors signing up as trade ally		5	5	1	1	1
05	Technical support for local supply-chain actors	Suggested KPI(s):	Program documentation & Direct engagement & comm. logs					
		# people attending classroom training		0	20	0	20	0
		# of 1-on-1 webinar or training sessions		5	10	10	5	5
		# of unsolicited calls for help		0	3	5	5	5
09	Trade events on conservation and lighting	Suggested KPI(s):	Program documentation					
		# of events with high level of visibility of inCharge brand		1	3	2	1	1
10	Supply-side actors develop projects	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s):	Direct engagement & comm. logs					
		# of new building manager being engaged with for the 1st time		10	10	5	5	5
		# of bldg managers solicited for market intel & updates		10	20	20	20	20
		# updates of web content		1	4	4	4	4
		# press releases		1	0	1	0	0
		# bill insert		1	1	1	1	1

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
13	Technical support for building managers	Suggested KPI(s): # of one-on-one webinar or training session with bldg managers # of unsolicited calls for help & % of calls that are successfully resolved	Direct engagement & comm. logs	2 0 n/a	5 2 100%	3 3 100%	3 2 100%	2 1 100%
14	Building owners/managers agree to initiate electricity efficiency projects	# of transactions in the lighting redesign incentive	Tracking System	Refer to the Program Design Report Exhibit 16, 17, 18, & 19				
15	Lighting redesign incentive	$ of incentive disbursement for lighting redesign	Tracking System	Refer to the Program Design Report Exhibits 20 & 21				
16	Electricity-efficient lighting opportunities are identified in the building	# of transactions in the lighting equipment incentive	Tracking System	Refer to the Program Design Report Exhibits 16, 17, 18, & 19				
17 & 18	Lighting equipment incentive and thus electricity-efficient lighting retrofit projects are implemented	$ of incentive disbursement for lighting equipment	Tracking System	Refer to the Program Design Report Exhibits 20 & 21				
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Tracking System	Refer to the Program Design Report Exhibits 22 & 23				
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed in under 10 business days	Tracking System	70%	80%	90%	95%	95%
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Direct engagement with supply-chain actors	No evaluation indicator	-			-		-
05	Technical support for local supply-chain actors	Suggested evaluation indicators: 1-to-10 scale, level of satisfaction with the training on average.	Supply-chain actors			7/10		n/a
09	Trade events on conservation, lighting and/or HVAC	Suggested evaluation indicators: % of market who can recall having seen inCharge at events	Participants, non-participants and supply-chain actors			60%		80%

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
10	Supply-side actors will actively seek to develop projects	Suggested indicator(s): % supply-chain actors who know the program	Supply-chain actors			90%		100%
		% of supply-chain actors who recommend the program to their customers				60%		80%
		% of relevant supply-side actors mapped out contributed to at least one transaction	Tracking system			30%		60%
		% of building manager who recall their provider telling them about program	Participants & non-participants			40%		
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction	Tracking system			40%		60%
		% of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants			70%		
13	Technical support for building managers	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the training on average.	Building managers (participants & non-part.)			7/10		
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
15	Lighting redesign incentive	Suggested indicator(s): % of participants who agree that the lighting redesign incentive got them to do a more sophisticated retrofit of their lighting system then they would have otherwise	Participants			60%		60%
		% of participating suppliers who confirm the above	Supply-chain actors			60%		60%
16	Electricity-efficient lighting opportunities are identified in the building	No evaluation indicator	-			-		-
17	Lighting equipment incentive	Suggested indicator(s): % of participants who agree that the incentive got them to install the energy efficient equipment in part or in full	Participants			60%		60%
		% of suppliers who agree that the incentive got their client to pursue with the install energy efficient equipment rather than the base in part or in full	Supply-chain actors			60%		60%
18	Electricity-efficient lighting retrofit projects are implemented	No evaluation indicator	-			-		-

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings.	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants			7/10		7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the lighting quality	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy				8/10		8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service Lighting Redesign and Equipment Incentive. No additional questions are needed.

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service Lighting Redesign and Equipment Incentive* have implications on the evaluation methods being employed:

- No savings are attributed to the redesign incentive; savings will be attributed only when the participants actually implement the projects and file a final incentive claim.
- The projects that will be partially financed by the Utilities through the program elements are “custom” projects. Participants and their service providers will provide an estimate of the savings – based on engineering calculations, no measurement required – this estimate will be verified by the program administrator and input in the tracking system as is. Thus, there will be a specific impact for each project. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on “archetype projects”; those are not going to be used as part of ex-post evaluation.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis will not be an option.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: lighting designers (population≈2), electrical/lighting

distributors (p=2), electrical contractors (p≈26), property managers (p≈8 large, ≈32 small) and the Yukon Energy Solutions Center.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the forms and tools (job aids) provided to participants and supply-chain actors to estimate the savings for each projects and review of the procedures to validate the savings as part of regular program operations.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Quality assurance of a sample of projects selected thorough all the transactions during the 5-year program operation window to establish the actual realized savings for each project in the sample, and ultimately establish the realization ratio for all of the population of projects.
    - It is assumed that manufacturer estimates of the demand (W) for each lamp/fixture as provided in the equipment specification sheets will not have to be measured.
    - Evaluators will be asked to spend more effort validating the running time estimates because this is where most of the inaccuracies will reside; either through research and scans of relevant evaluation reports thorough North America, surveying with the participants, or actual running time measurements.
    - The sample size will be established by the evaluators in order to achieve a level of precision on the realization ratio of ±15% with a one-tailed confidence interval of 90%. Evaluators are suggested to stratify the population by project impact and use a differentiated sampling approach for each stratum in order to maximize value of impact evaluation.
- Review of site visit reports generated by the administration staff to estimate installation/removal rates and uncover issues related with persistence of the savings and the alike.
- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.2 General Service High Efficiency Refrigeration Program

4.2.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers who retrofit their refrigeration systems and/or install refrigeration controls. This will be a custom incentive for equipment and installation, i.e. it will be determined using a dollar per kilowatt-hour rate for each kilowatt-hour

of savings realized annually as compared with the pre-retrofit consumption and demand level. In addition to the incentive, the Utilities will provide extensive refrigeration-specific technical assistance to identify the opportunities, to develop the projects, to manage the construction works, and to measure and monitor the performance of the projects. It is expected that this program element will aim at hockey and curling arenas and grocery stores in particular.

Eligible Measures

The proposed incentive levels and archetype refrigeration projects are presented in Exhibit 12 and Exhibit 13.

Exhibit 12: Archetype High Efficiency Refrigeration Projects – Custom Incentive for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM98	Typical Low-Cost No-Cost Refrigeration Project - Food	6.55 kWh/ft2	.00074 kW/ft2	95%	$1.73/ft2	10.0 yr	$1.31/ft2	30,000 ft2
ECM99	Typical Deep Retrofit Refrigeration Project - Food	13.48 kWh/ft2	.00153 kW/ft2	95%	$5.87/ft2	10.0 yr	$2.70/ft2	30,000 ft2

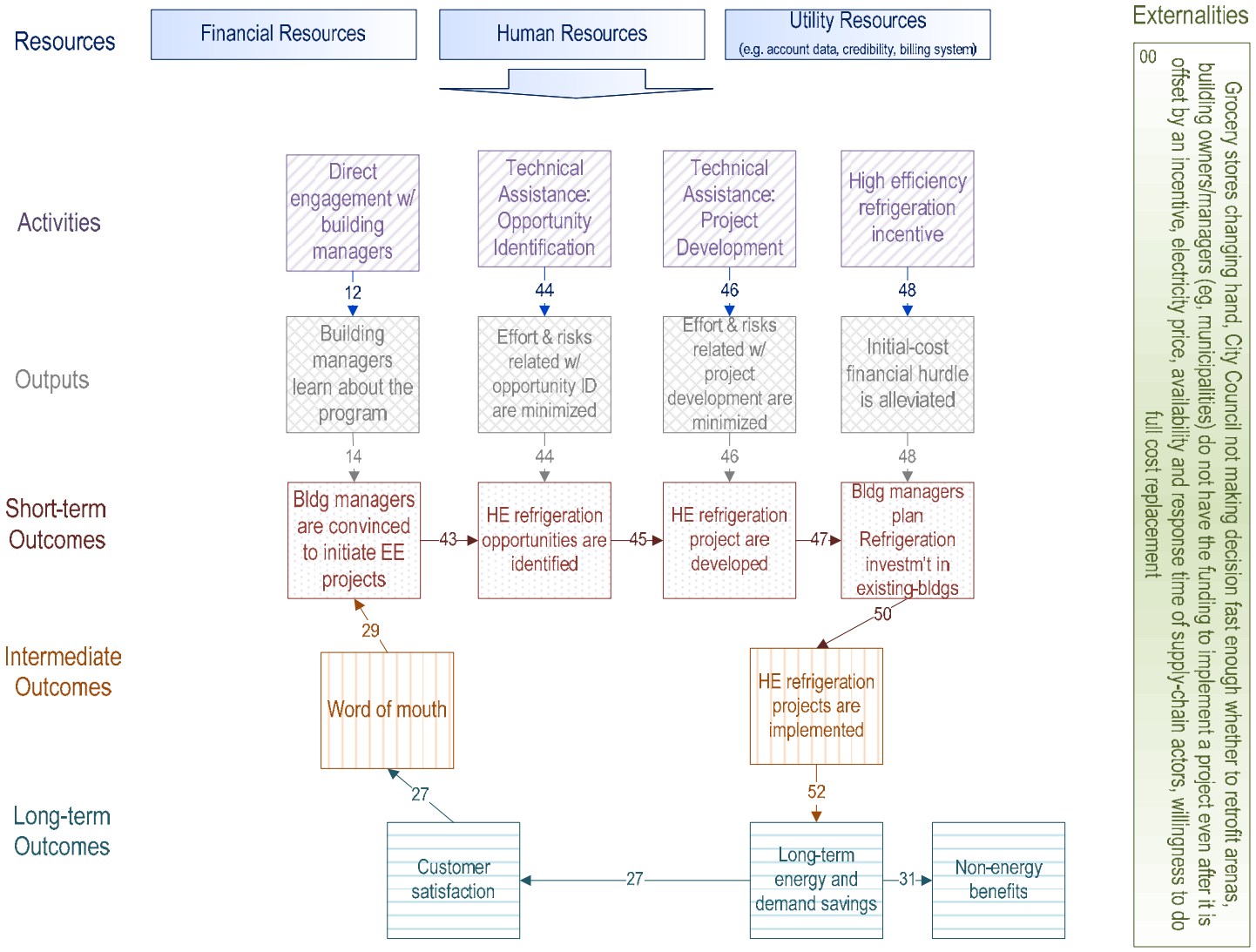
Exhibit 13: Archetype High Efficiency Refrigeration Projects – Custom Incentive for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM1002	Typical Refrigeration Project - Ice Rink	2.49 kWh/ft2	.00034 kW/ft2	95%	$0.72/ft2	20.0 yr	$0.40/ft2	25,000 ft2

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 14: Logic Model for the General Service High Efficiency Refrigeration Element



Link #	Narrative
00	Externalities: The program effectiveness and impact will be influenced by the following externalities: grocery store ownership changes, slow decision-making on the part of City Council regarding whether or not to retrofit arenas, a lack of funding for building owners/managers (e.g., municipalities) to implement a project even after it is offset by an incentive, the price of electricity, the availability and response time of supply-chain actors, and the willingness to do a full cost replacement.
12	Direct engagement with supply-chain actors. The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings, and through public relations activities like press releases sent to the local newspapers and radio stations, web content and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities.

Link #	Narrative
43	Building owners/managers are offered the free services of energy engineers representing the Utilities to assess their refrigeration system to identify efficiency opportunities. They participate because their risk exposure and level of effort are minimized.
44	The Utilities provide technical assistance to the building owners/managers in the form of an assessment of the refrigeration system to identify energy efficiency opportunities. As a result, high efficiency refrigeration opportunities are identified. It is assumed that the Utilities are offering services NOT being offered for profit by other market actors because the target market niche is too small to be lucrative. It is not displacing or blocking free-market mechanisms (i.e. not blocking an existing mechanism or mechanism in the making).
45	After the high efficiency refrigeration opportunities are identified, the participant is offered more support to develop the project. The participant is asked to make a commitment. If the resulting project is a cost-effective investment, the participant agrees to carry on and implement the project. Otherwise, the participant will have to pay part of the cost of the technical assistance. The participant accepts because the level of risk he/she is asked to take is fair.
46	The Utilities provide technical assistance to develop the high efficiency refrigeration project in the form of a feasibility study and/or an investment-grade audit. If the participant implements the proposed design, the feasibility study will be free of charge.
47	The participants are presented with investment- and implementation-ready high efficiency refrigeration projects.
48	The Utilities will pay an incentive to participants who implement the high efficiency refrigeration projects that are identified. The incentive will alleviate the initial-cost hurdle of the high-efficiency refrigeration retrofit projects.
50	Because high-efficiency projects will have been subsequently identified and then developed by the Utilities, and because the Utilities will alleviate the initial-cost hurdle, high-efficiency refrigeration retrofit projects will be implemented.
52	The high-efficiency refrigeration retrofit projects will yield long-term electricity and demand savings.
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry, perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits and/or maintain the benefits they used to have with baseline systems. For example, the Utilities will seek to ensure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and increase property value.

4.2.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 14 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 15. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 15 are provided in Section 4.1.2.

Exhibit 15: Management-by-Objective Framework for the General Service High Efficiency Refrigeration Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building manager being engaged with for the 1st time # of bldg managers solicited for market intel & updates	Direct engagement & comm. logs	10 10	- 10	- 10	10 10	- 10
14, 43 & 44	Building owners/managers are offered free energy engineering services to identify opportunities	Suggested KPI(s): # opportunity identification studies	Program documentation	0	10	0	10	0
45 & 46	Building owners/managers are offered support to develop the project	Suggested KPI(s): # feasibility studies	Program documentation	0	3	3	3	3
47, 48 & 50	High efficiency refrigeration incentive and thus electricity-efficient refrigeration retrofit projects are implemented[11]	$ of incentive disbursement for HE refrigeration	Program documentation	$0K *w/gov* $0	$0K $0	$122K $132K	$0K $0K	$122K $132K
52	The electricity-efficient refrigeration retrofit projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Program documentation	Refer to the Program Design Report Exhibits 35 & 36				
27	Building owners/managers will be satisfied by the projects that they implemented	No associated tracked KPIs	-	-	-	-	-	-
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction % of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Project documentation Participants & non-participants			40% 70%		60%

[11] Refer to the Program Design Report Exhibits 33 & 34

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
43, 44, 45, & 46	Building owners/managers are offered free energy engineering services to identify opportunities	% of participants who agree that the technical assistance got them to do a more sophisticated retrofit of their refrigeration system then they would have otherwise	Participants			60%		60%
47, 48 & 50	High efficiency refrigeration incentive and thus electricity-efficient refrigeration retrofit projects are implemented	% of participants who agree that the incentive got them to install the energy efficient equipment in part or in full	Participants			60%		60%
52	The electricity-efficient refrigeration retrofit projects will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-	-	-	-	-	-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants			7/10		7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants	Participants in any GS program elements			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the refrigeration quality	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy				8/10		8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service High Efficiency Refrigeration Program. In addition, the following question should be explored:

- How effective was the technical assistance at supporting prospective participants in making a decision with regard to energy efficiency projects?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service High-Efficiency Refrigeration Incentive* have implications on the evaluation methods being employed:

- Relatively few projects are anticipated (5 to 10), therefore transactional infrastructure will be basic and documentation will be on a project-by-project basis.
- No savings are attributed to the technical assistance phases of the project; savings will be attributed only when the participants actually implement the projects.
- An aggregate of the M&V results from the technical assistance phases of each project can be fed into the program-level evaluation.
- Participants and their service providers will provide an estimate of the savings – based on engineering calculations, no measurement required – this estimate will be verified and documented by the program administrator. Thus, there will be a specific impact for each project. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on "archetype projects"; those are not going to be used as part of ex-post evaluation.
- These projects are planned to occur in two waves: a first wave is planned to start around Y2-Q2, construction is to end on Y3-Q3, and the post-retrofit measurement period – expected to last for one year – is to end around Y4-Q3. The second wave will start on Y4-Q2 then follow a similar schedule. The completion of the M&V work for that second wave falls outside of the program window.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: store managers (population≈4); hockey/curling arena operators (p≈9); refrigeration contractors (p≈3); and the high-efficiency refrigeration consultant. Based on the results of the first half of the program period, the second half of the program period may involve: convenience stores, small grocery stores, and restaurants (p≈35).

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the technical assistance reports provided to participants to assess soundness of calculations and the proposed solutions, and effectiveness of the documents produced at supporting prospective participants in making a decision with regard to energy efficiency projects.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact of this program element will be evaluated based on the aggregated results of all of the project-level M&V reports completed as part of technical assistance components of the program. The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of

utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days. Please refer to Section 3.2 for additional details.

- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.

- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.3 General Service ENERGY STAR Computer Incentive

4.3.1 Program Description Summary

The Utilities will pay an incentive to companies and organizations to have their computer equipment replaced with ENERGY STAR computer equipment.

A prescriptive incentive approach will be as follows: the Utilities will pay a flat amount of money per unit to owners/managers when computers and computer equipment from a prescriptive list of eligible products are purchased.

Equipment eligibility is tracked using a prescriptive list, so a pre-approval step is not necessary. The participation process is therefore very straightforward: the participant will submit a simple application form and provide backup documentation (e.g. invoices) to receive the incentive payment.

Eligible Measures

The proposed incentive level and archetype projects for the ENERGY STAR computer incentive are presented in Exhibit 16 and Exhibit 17.

Exhibit 16: Prescriptive List of ENERGY STAR Computer Conservation Measures for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM101	ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	95%	$0.00/unit	4.0 yr	$30.00/unit
ECM102	ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	95%	$0.00/unit	4.0 yr	$10.00/unit

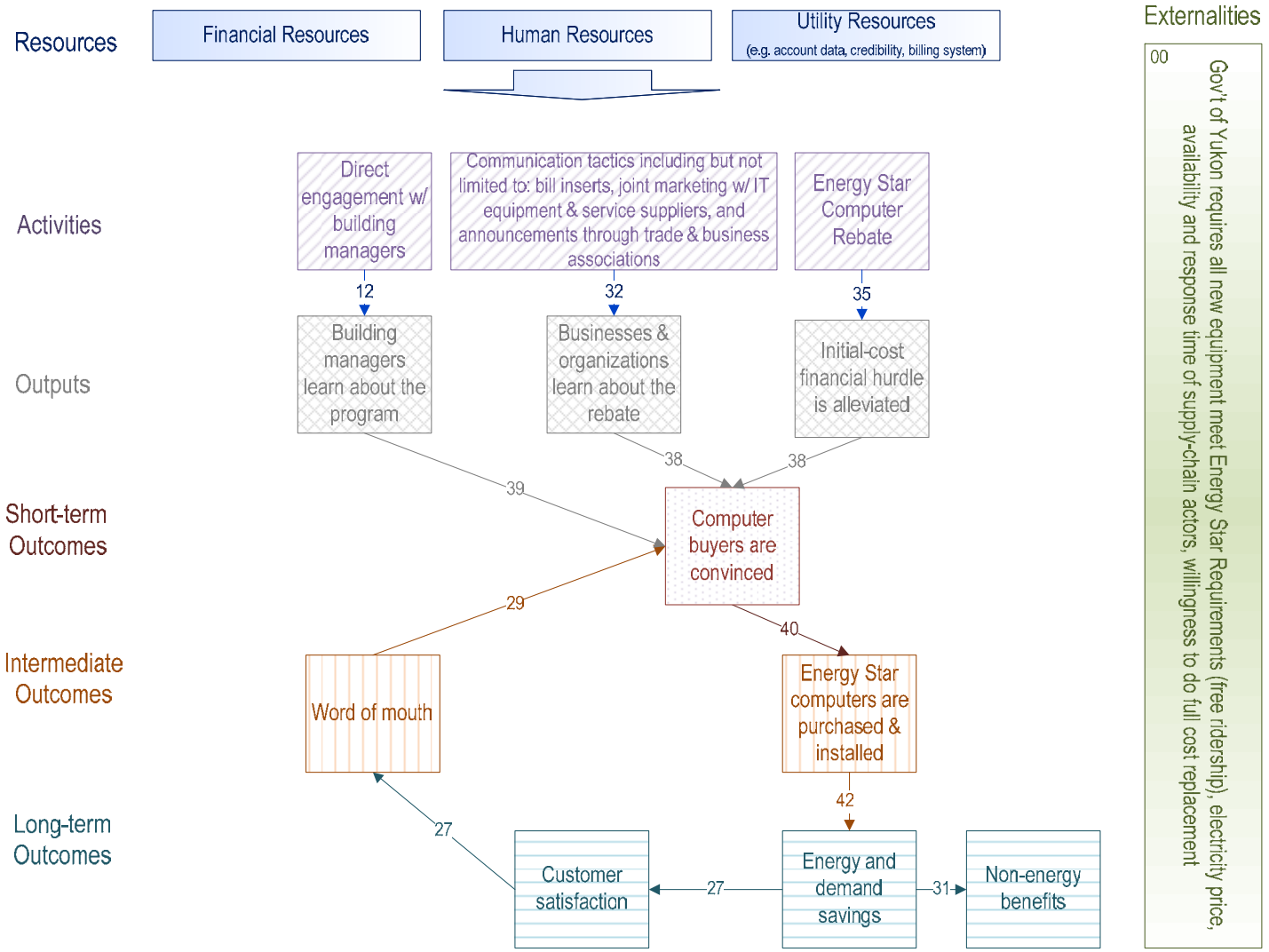
Exhibit 17: Prescriptive List of ENERGY STAR Computer Conservation Measures for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM1012	Gov. ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	55%	$0.00/unit	4.0 yr	$18.00/unit
ECM1022	Gov. ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	55%	$0.00/unit	4.0 yr	$6.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 18: Logic Model for the General Service ENERGY STAR Computer Element



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: the Gov't of Yukon's requirement that all new equipment meets ENERGY STAR standards (free ridership), the price of electricity, the availability and response time of supply-chain actors, and the willingness to do full cost replacements.
12	The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program. Some building owners/managers also make IT equipment purchase decisions.
32	The Utilities carry out many tactics to inform computer buyers at businesses and organizations based in the Yukon. As a result, the computer buyers will learn about the incentive offering.
35	The Utilities will pay an incentive to computer buyers in exchange for the purchase of an ENERGY STAR Computer. The incentive will alleviate the initial-cost hurdle of the ENERGY STAR Computer and will be a convincing selling point.

Link #	Narrative
38	Because computer buyers will know about the offering and because they are offered a rebate designed to influence them, they will buy ENERGY STAR computers.
40	ENERGY STAR computers are purchased instead of standard computers.
42	The ENERGY STAR computers will yield electricity and demand savings during their 4-year lifetime.
27	Participants will be satisfied with the ENERGY STAR computer that they purchased. They will relay their experiences to other computer buyers in the Yukon, generating word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause computer buyers to buy more ENERGY STAR computers.
31	It is assumed that the staff using ENERGY STAR computers will have the same user-experience as with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems turn on and off as fast as non-ENERGY STAR computers, and that their processors are as fast, etc.

4.3.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 10 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 19. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 19 are provided in Section 4.1.2.

Exhibit 19: Management-by-Objective Framework for the General Service ENERGY STAR Computer Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building managers being engaged with for the 1st time	Direct engagement & communication logs	10	10	5	-	-
		# of building managers contacted with program intel & updates		10	20	20	-	-
32	Utilities carry out many communication tactics to inform businesses & organizations about the rebate	# updates of web content	Tracking System	1	4	4	-	-
		# press releases		1	0	1	-	-
		# joint marketing w/IT equip suppliers		1	1	1	-	-
		# bill insert		1	1	1	-	-
		# email blasts		0	2	4	-	-
35 & 40	Participants receive a rebate[12]	$ of incentive disbursement for ENERGY STAR computers/monitors	Tracking System	$2K	$10K	$17K	-	-
				w/gov: $6K	$35K	$57K	-	-

[12] Refer to the Program Design Report Exhibits 45 & 46

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
38 & 39	ENERGY STAR computers are purchased & installed[13]	Suggested KPI(s): # of rebates claimed + stipulated 30% "spillover"[14]	Tracking System	96 *w/gov:* 386	612 2449	999 3996	- -	- -
42	The ENERGY STAR computer installations will yield electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand		Refer to the Program Design Report Exhibits 47 & 48				
27	Participants will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in under 10 days		70%	80%	90%	-	-
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-

Part B -- To Be Visited, Checked and Reported On by Evaluators			Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction	Tracking system			40%		
32	Utilities carry out many communication tactics to inform businesses & organizations about the rebate	Suggested indicator(s): % of building managers who can recall one of the following: bill inserts, web content, or contact from IT suppliers	Participants & non-participants			70%		
35 & 40	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate got them to purchase the energy efficient products	Participants			60%		
38 & 39	ENERGY STAR computers are purchased & installed	No evaluation indicator	-			-		-
42	The ENERGY STAR computer installations will yield electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
27	Participants will be satisfied by the products that they bought	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program 1-to-10 scale, level of satisfaction with their energy efficient products	Participants Participants			8/10 7/10		
29	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		

[13] Refer to the Program Design Report Exhibits 43 & 44 (they do not include the estimated spillover)
[14] This is one way to extrapolate the total number of shoppers influenced by the program (including those that purchased and installed rebate-eligible products without claiming a rebate)

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
31	Non-energy benefits	Suggested indicator(s): % of participants who believe that performance of the ENERGY STAR computer is equal to that of a standard computer % of participants who believe that buying an ENERGY STAR computer will be important or very important to them next time they buy a computer, even in the absence of a rebate program.	Participants			90% 70%		

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service ENERGY STAR Computer Incentive without nuance. No additional questions are needed.

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service ENERGY STAR Computer Incentive* have implications on the evaluation methods employed:

- Participants will receive a flat incentive per unit after they purchase computers and computer equipment from a prescriptive list of eligible products. Deemed savings and the use of a TRM are recommended.
- The ENERGY STAR computer incentive will close in Q4 of Y3.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis or whole-building M&V will not be an option.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: IT equipment suppliers and retail stores (p≈20), property managers (p≈8 large, ≈32 small) and the Yukon Energy Solutions Centre.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Primarily, the impact will be computed based on the number of rebate transactions, deemed savings and the content of the TRM. The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.

- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.4 General Service New Construction Incentive

4.4.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers for high performance new buildings. The incentive will have two paths: a prescriptive path for small buildings and a custom path for large buildings. The prescriptive incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard. The custom incentive will be determined using a dollar per kilowatt-hour of annual savings rate for each kilowatt-hour of savings realized above a minimum level. Savings will be determined through building modeling.

Eligible Measures

The proposed incentive level as well as archetype projects are presented in Exhibit 20 and in Exhibit 21.

Exhibit 20: Archetype Electricity-Efficient Non-Government New Construction Projects

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM89	Typical High-Performance New Building - 25% Better	5.93 kWh/ft2	.00135 kW/ft2	95%	$2.00/ft2	20.0 yr	$1.50/ft2	11,759 ft2
ECM90	Typical High-Performance New Building - 40% Better	9.49 kWh/ft2	.00217 kW/ft2	95%	$6.00/ft2	20.0 yr	$4.00/ft2	11,759 ft2

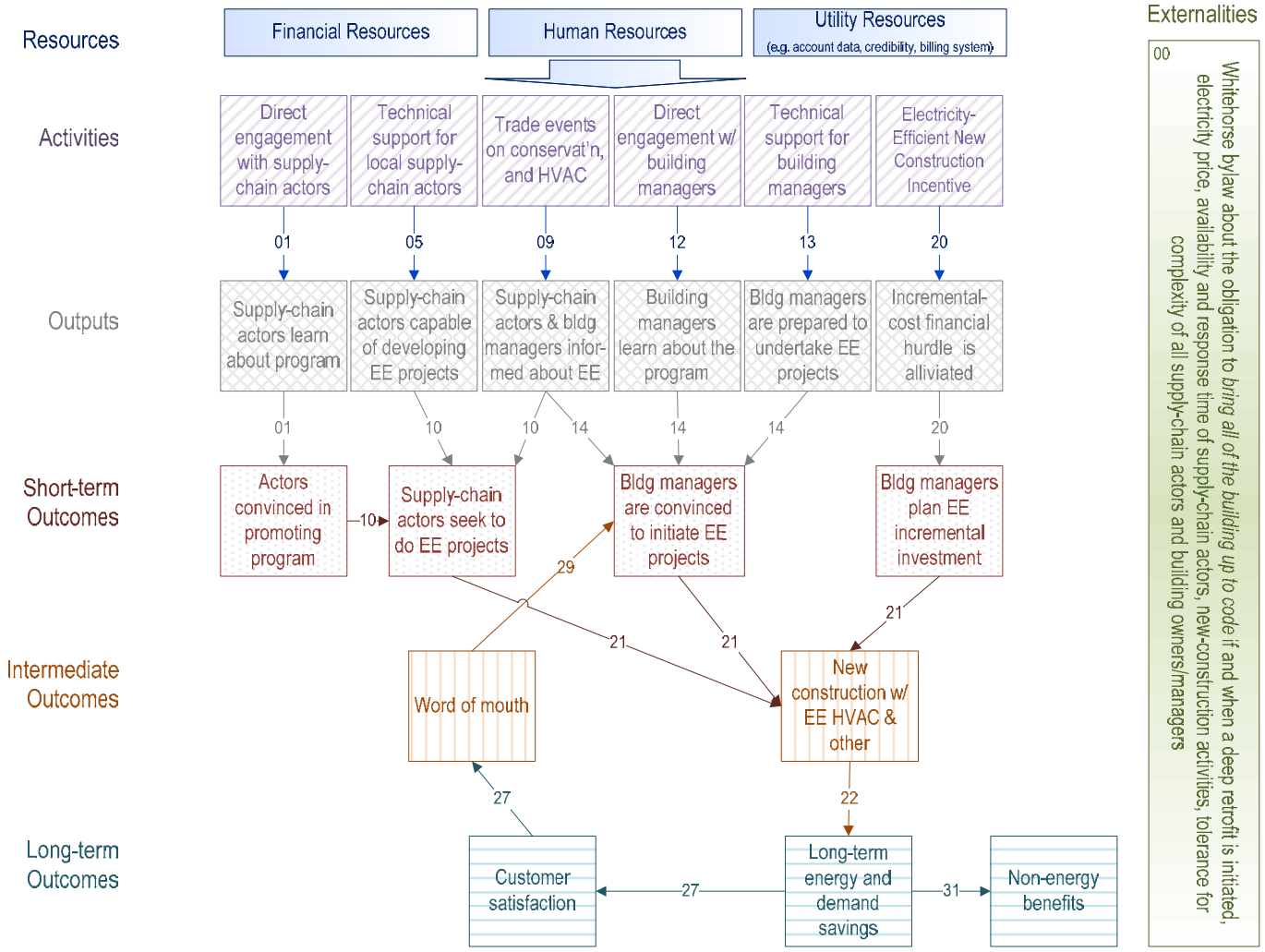
Exhibit 21: Archetype Electricity-Efficient Government New Construction Projects

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM892	Gov. Typical High-Performance New Building - 25% Better	5.93 kWh/ft2	.00135 kW/ft2	95%	$2.00/ft2	20.0 yr	$0.90/ft2	26,209 ft2
ECM902	Gov. Typical High-Performance New Building - 40% Better	9.49 kWh/ft2	.00217 kW/ft2	95%	$6.00/ft2	20.0 yr	$2.40/ft2	26,209 ft2

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 22: Logic Model for the General Service New Construction Incentive



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: Whitehorse bylaws on the obligation to bring all of the buildings up to code if and when deep retrofits are initiated, the price of electricity, the availability and response time of supply-chain actors, new-construction activities, and tolerance for complexity of all supply-chain actors and building owners/managers. The program administrator should monitor these externalities and adapt the implementation approach as necessary.
01	The Utilities will carry out direct engagement with electrical distributors, lighting designers, electrical contractors, as well as with HVAC contractors, HVAC designers, control designers and architects through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and engage with supply-chain actors so that they promote them.

Link #	Narrative
05	The Utilities will offer technical support to the supply-chain actors in two different forms: (1) hands-on training on the program tools, forms and procedures; on advanced electricity efficiency lighting design; and on the business aspects of electricity efficiency: energy audits, business cases, energy performance contracting, and electricity efficiency financing. (2) The Utilities will act as a broker to procure technical expertise from highly specialized lighting experts recruited throughout North America upon request from the local actors. In addition, the Utilities will disseminate information on recommended lighting equipment (brand-neutral, to the extent possible) in the form of printed brochures, newsletters or web content.
09	The Utilities propose to support any form of trade organizations or trade events by sponsoring and attending trade events that gather local building owners/managers and/or supply-chain actors. The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories, and share their lessons learned.
10	Supply-side actors will actively seek to develop projects because they were engaged with by the Utilities, because they were trained and are capable of offering electricity-efficiency services, and because they were provided with networking opportunities with potential clients (building owners/managers) at trade events.
12	The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings; and through public relations activities like press releases sent to the local newspapers and radio, web content, and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
13	The Utilities will offer customized technical support to building owners/managers to help them to initiate projects. The Utilities could include support to plan investment in assets, and to identify in which buildings to develop projects; support to make optimal decisions on implementation and procurement approach, and support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities, because they were provided with technical support to decide where to start and how to do it, and because they networked with supply-side actors, perhaps at the trade events supported by the Utilities.
20	The Utilities will pay an incentive to new building owners/managers for electricity-efficient new buildings construction. The incentive will alleviate the initial-cost hurdle of the construction of electricity-efficient buildings. The incentive will be performance-based and be paid for buildings that are more electricity efficiency than the combination of the 2011 National Energy Code of Canada for Building and the City of Whitehorse's Building and Plumbing Bylaw.
21	Electricity-efficient new buildings constructions are implemented because the supply-chain actors were seeking to work on electricity-efficient new construction projects, and because the initial-cost hurdle of the construction of electricity-efficient buildings was alleviated.
22	The electricity-efficient new buildings will yield long-term electricity and demand savings.
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry; perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and have increased property value.

4.4.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 22 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 23. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 23 are provided in Section 4.1.2.

Exhibit 23: Management-by-Objective Framework for the General Service New Construction Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Direct engagement with supply-chain actors	Suggested KPI(s): # of new actors being engaged with for the 1st time	Direct engagement & communication logs	6	12	-	-	-
		# of actors solicited for market intel & updates		6	18	18	18	18
		# of actors signing up as trade ally		5	5	1	1	1
05	Technical support for local supply-chain actors	Suggested KPI(s): # people attending classroom training	Program documentation & Direct engagement & comm. logs	0	10	0	10	0
09	Trade events on conservation and HVAC	Suggested KPI(s): # of events with high level of visibility of inCharge	Program documentation	1	1	1	1	1
10	Supply-side actors develop projects	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building manager being engaged with for the 1st time	Direct engagement & comm. logs	10	10	5	5	5
		# of bldg managers solicited for market intel & updates		10	20	20	20	20
		# updates of web content		1	4	4	4	4
		# press releases		1	0	1	0	0
		# bill insert		1	1	1	1	1
13	Technical support for building managers	Suggested KPI(s): # of one-on-one webinar or training session with bldg managers	Direct engagement & comm. logs	2	5	3	3	2
		# of unsolicited calls for help & % of calls that are successfully resolved		0 n/a	2 100%	3 100%	2 100%	1 100%

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
14	Building owners/managers agree to initiate electricity efficiency projects	# of transactions in the new construction incentive	Tracking System	Refer to the Program Design Report Exhibits 56 & 57				
20 & 21	New construction incentive and thus electricity-efficient projects are implemented[15]	$ of incentive disbursement for new construction	Tracking System	$0 *w/gov* $0K	$4K $6K	$19K $25K	$30K $39K	$34K $45K
22	The electricity-efficient projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Tracking System	Refer to the Program Design Report Exhibits 60 & 61				
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed below 10 business days	Tracking System	70%	80%	90%	95%	95%
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Direct engagement with supply-chain actors	No evaluation indicator	-			-		-
05	Technical support for local supply-chain actors	Suggested evaluation indicators: 1-to-10 scale, level of satisfaction with the training on average.	Supply-chain actors			7/10		n/a
09	Trade events on conservation and HVAC	Suggested evaluation indicators: % of market who can recall having seen inCharge at events	Participants, non-participants and supply-chain actors			60%		80%
10	Supply-side actors will actively seek to develop projects	Suggested indicator(s): % supply-chain actors who know the program % of supply-chain actors who recommend the program to their customers % of relevant supply-side actors mapped out contributed to at least one transaction % of building manager who recall their provider telling them about program	Supply-chain actors Tracking system Participants & non-participants			90% 60% 30% 40%		100% 80% 60%
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction % of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Tracking system Participants & non-participants			40% 70%		60%

[15] Refer to the Program Design Report Exhibits 58 & 59

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
13	Technical support for building managers	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the training on average.	Building managers (participants & non-part.)			7/10		
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
20	New construction incentive	Suggested indicator(s): % of participants who agree that the incentive got them to work on an energy efficient building design in part or in full % of suppliers who agree that the incentive got their client to increase the energy performance of their building	Participants Supply-chain actors			60% 60%		60% 60%
21	Electricity-efficient projects are implemented	No evaluation indicator	-	-	-	-	-	-
22	The electricity-efficient projects will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-	-	-	-	-	-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program 1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants Participants			8/10 7/10		8/10 7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		60% 30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the lighting quality 1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy	Participants			9/10 8/10		9/10 8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service New Construction Incentive. In addition, the following questions will be explored:

- Is the baseline building standard for this program sound, and should the baseline be changed mid-course?
- Is the market ready for a more stringent building code?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service New Construction Incentive* have implications on the evaluation methods employed:

- Under the prescriptive path, the incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard. The standard will be designed to be slightly more stringent than the Model National Energy Building Code minus 25% (MNEBC -25%) and the City of Whitehorse's Building and Plumbing Bylaw.
- Under the custom-incentive path (or performance path), the custom incentive will be determined using a dollar per kilowatt-hour of annual savings rate for each kilowatt-hour of savings that are realized above a minimum level. Savings will be determined through building energy modeling. The baseline and modeling requirements will be the same as those for the Canada Green Building Council's LEED building certification. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on "archetype projects"; those are not going to be used as part of ex-post evaluation.
- The program performance was modeled before the launch using the archetype projects presented in Exhibit 20 and in Exhibit 21Exhibit 21. However, during program implementation, each transaction is treated as a custom project, with a specific level of electricity and demand savings, and a specific total incentive amount.
- This is an incentive for new building constructions, and since there are no "pre-build" utility bills or measurements, whole-building M&V is not applicable (Option C of the IPMVP).
- Calibrated building energy modeling might be practical (that is: Option D according to the IPMVP). The Utilities are working under the assumption that the number of transactions will not be large enough to justify an Option-D methodology; and regular building energy modeling will be sufficient. For the benefit of the readers: under the calibrated building energy modeling approach, building analysts adjust their project-scenario model ex post so that the model reflects early utility bills. Many changes that are uncovered then must also be applied to the base-case scenario. The resulting "calibrated" saving estimate is then considered to be more accurate. It is expected that the program element will involve or have implications on the following market actors and stakeholders: HVAC/control designers and contractors (p≈18), property managers (p≈8 large), architects (p≈3), and the Yukon Energy Solutions Centre.

Based on the above, the suggested process evaluation methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the forms and tools (job aids) provided to participants and supply-chain actors to estimate the savings for each projects and review of the procedures to validate the savings as part of regular program operations.

- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Quality assurance of a sample of projects selected thorough all the transactions during the 5-year program operation window to establish the actual realized savings for each project in the sample, and ultimately establish the realization ratio for all of the population of projects.
    - Verification will be based on “as-built” blueprints that shall be collected as part of program operations.
- Stipulated measure lifetime will be assumed to be 20 years and stipulated net-to-gross ratio will be assumed to be 95%. These stipulated values are to be validated by the evaluators during the finalization of the EM&V plan.
- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.5 Residential LED Lighting & Automotive Heater Timer Rebates

4.5.1 Program Description Summary

The Utilities will provide a flat incentive per unit to shoppers and housing developers after they purchase LED lighting lamps or fixtures or a timer for an automotive heater, car warmer and/or battery blanket selected from a prescriptive list of eligible products.

The Utilities will explore three possible rebate delivery mechanisms: (1) instant rebate at the point of purchase, (2) mail-in rebate, or (3) both. Instant-rebates are generally preferred by participants and will, therefore, be pursued first. However, the Utilities retain the option to complete a mail in rebate if market or regulatory conditions preclude from using instant rebates.

The Utilities retain the right to modulate the rebate though the same fiscal year to be able to react to market conditions and use marketing tactics to drive up the demand. In addition, the Utilities retain the right to update the incentive levels, the list of eligible products and the LED incentive budget on an annual basis.

Automotive heater timers gained a bad reputation in the Yukon because they reportedly failed. In order to address this, the Utilities envision applying the following tactics:

- The Utilities will start by promoting indoor automotive heater timers with the housing developers. Indoor timers are not subjected to cold weather and are therefore more reliable.
- The Utilities know that outdoor automotive heater timers are being promoted by utilities in Alaska. The Utilities intend to research the automotive heater timers that the Alaskan utilities are promoting, to test them in the Yukon. The Utilities will start promoting these automotive heater timers once the reliability issue is resolved.

Eligible Measures

The first list of prescriptive measures will include the items presented in Exhibit 24.

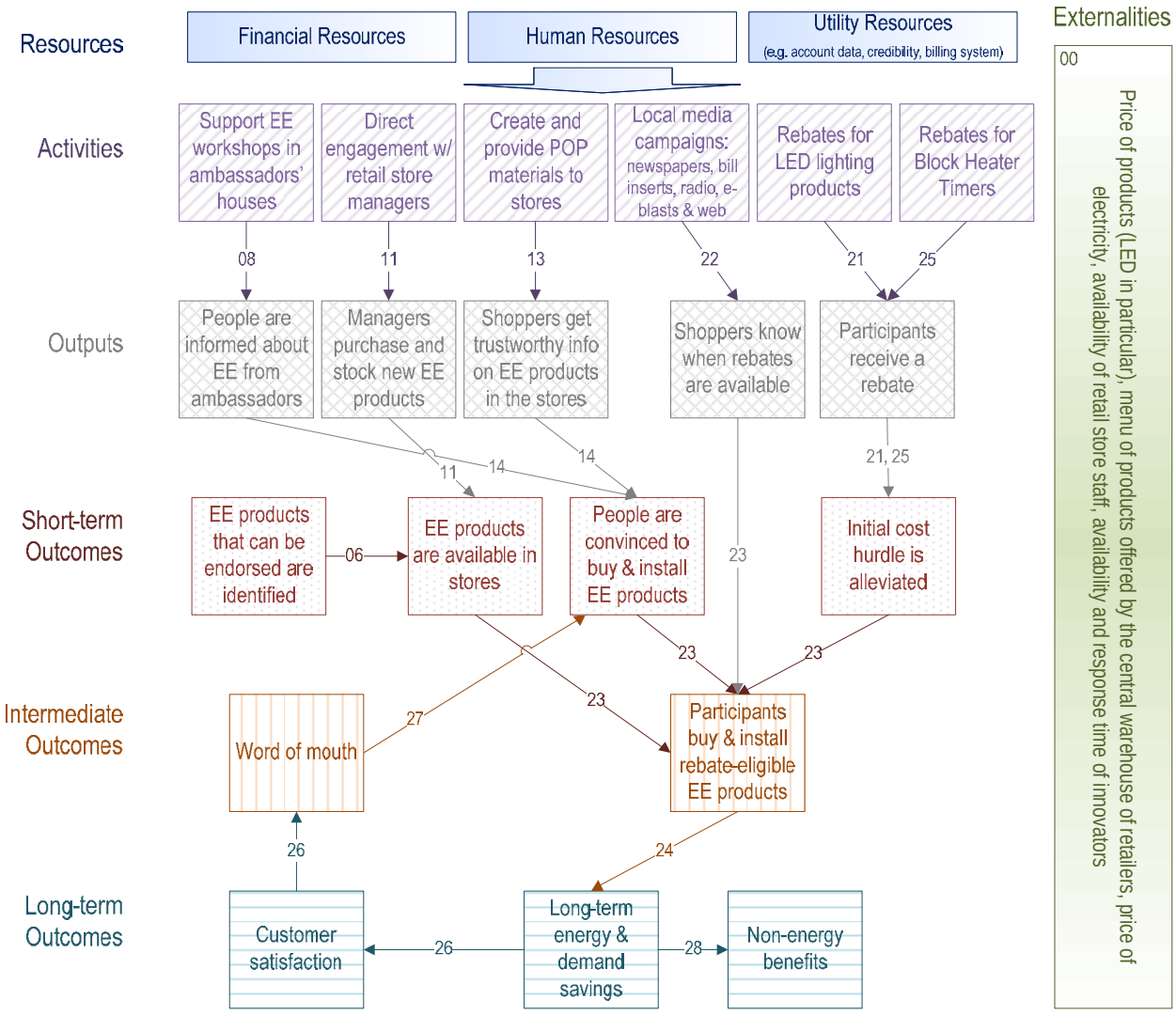
Exhibit 24: Prescriptive List of Residential LED Lighting and Automotive Heater Timer Energy Conservation Measures

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM151	Block Heater Timer	130 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$20.00/unit
ECM24	12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	110%	$44.00/unit	20.0 yr	$18.00/unit
ECM60	8W LED A19 Bulb	32.0 kWh/unit	0.011 kW/unit	110%	$30.00/unit	20.0 yr	$12.00/unit
ECM61	LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	110%	$20.00/unit	20.0 yr	$10.00/unit
ECM62	LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	110%	$51.00/unit	20.0 yr	$20.00/unit
ECM63	LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	110%	$43.00/unit	20.0 yr	$20.00/unit
ECM44	Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	80%	$25.00/unit	10.0 yr	$10.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 25: Logic Model for the Residential LED Lighting & Automotive Heater Timer Rebates



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, availability of retail store staff, availability and response time of innovators The program administrator should monitor these externalities and adapt the implementation approach based on them.
06	The consumer responses provided on the scorecards will be aggregated, analyzed and provided to the store managers. The Utilities will be able to endorse certain EE products because customer satisfaction will be good. The results will be presented to the retail store managers, and feed the communication and POP materials. It is expected that store managers will react by stocking more of these products and allocate more shelf space.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, automotive heater timers and innovative heating and DHW systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign starting in June of each year through local radio, local newspapers, co-op advertisement with retailers and in stores, email blast, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available. The marketing tactics used will create a sense of urgency and push Yukon shoppers to make the right purchase decision; it is expected to boost overall program uptake as compared a continuously available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (indoor or outdoor) from selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	It is assumed that shoppers will perceive new non-energy benefits; and/or the maintenance of benefits they used to h baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

4.5.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 25 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 26. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 26 are provided in Section 4.1.2.

Exhibit 26: Management-by-Objective Framework for the Residential LED Lighting and Automotive Heater Timer Rebates

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
06	Scorecard results will be analyzed and provided to store managers	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	10	5	3	2	0
		EE products that can be endorsed by the Utilities are reviewed and identified (Yes/No)		Yes	Yes	Yes	Yes	Yes
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	0	2	4	10	0
		# people attending workshops		8	8	8	8	-
11	Direct engagement with retail store managers	Suggested KPI(s): # of new store managers being engaged with for the 1st time	Direct engagement & communication logs	20	-	-	-	-
		# of store managers contacted with program intel & updates		20	20	20	20	20
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s): # stores with POP materials	Program documentation	5	10	10	10	10
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	Yes	Yes	Yes	Yes
14 & 23	Shoppers buy and install rebate-eligible products[16]	Suggested KPI(s): # of units claimed + estimated 30% "spillover"[17]	Tracking System	1019	4439	4491	4491	4491
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[18]	MWh of avoided lifetime electricity consumption	Estimate based on rebates processed + spillover	718	3149	3207	3207	3207
		MWh of avoided annual electricity consumption		36	199	368	537	705
		MW of avoided coincident electricity demand		13	71	131	191	252
21 & 25	Participants receive a rebate[19]	$ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	$12K	$51K	$52	$52K	$52K

[16] Refer to the Program Design Report Exhibit 70 (they do not include the estimated spillover)
[17] This is one way to extrapolate the total number of shoppers influenced by the program (including those that purchased and installed rebate-eligible products without claiming a rebate).
[18] Refer to the Program Design Report Exhibit 72
[19] Refer to the Program Design Report Exhibit 71

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
22	Shoppers learn about rebates through local media campaigns	# updates of web content # newspaper/radio advertisements # bill insert # email blasts	Tracking System	1 1 1 1	4 1 1 1	4 1 1 1	4 1 1 1	4 1 1 1
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	80%	90%	95%	95%
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
06	Scorecard results will be analyzed and provided to store managers	Suggested indicator(s): % store managers who agree that scorecards helped influence purchasing and/or shelf space decisions	Store managers			70%		70%
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
11	Direct engagement with retail store managers	Suggested indicator(s): % store managers who know the program % of store managers contributed to at least one transaction	Store managers Tracking system			100% 60%		100% 70%
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials % of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product	Shoppers and Participants			70% 50%		70% 50%
14 & 23	Shoppers buy and install rebate-eligible products	No evaluation indicator	-			-		-
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants			60%		60%
22	Shoppers learn about rebates through local media campaigns	Suggested indicator(s): % of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants			70%		

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s):						
		1-to-10 scale, level of satisfaction with the overall rebate program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient products	Participants			7/10		7/10
27	Word-of-mouth	Suggested indicator(s):						
		% heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
28	Non-energy benefits	Suggested indicator(s):	Participants					
		1-to-10 scale, level of satisfaction with the lighting/automotive heater timer quality				9/10		9/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential LED Lighting and Automotive Heater Timer Rebate. In addition, the following questions will be explored:

- How shoppers are influenced by the rebate, but do not ultimately redeem the rebate?
- Has the engagement with the retailers, including sharing the scorecards and the research performed on their behalf, influenced their habits (such as stocking, merchandizing, promotions, and adding new products) to sell more energy efficient products?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential LED Lighting and Automotive Heater Timer Rebates* have implications on the evaluation methods employed:

- Participants will receive a flat incentive per unit after they purchase LED lighting lamps or fixtures or a timer for an automotive heater timer, car warmer and/or battery blanket from a prescriptive list of eligible products. Deemed savings and the use of a TRM are recommended.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis or whole-building M&V will not be an option.
- Shoppers who are influenced to purchase rebate-eligible products in many cases will not claim the rebate. Hence, the amount of rebate disbursements will not provide a complete indicator of the program impact.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: retail store managers (p≈20), landlords (p≈50),

shoppers (p≈20,000), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews with supply-chain actors, and phone or online surveys with participants and non-participants, but evaluators will be able to suggest an alternative approach if necessary. Mystery shoppers and retail intercepts might also be considered. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the point-of-purchase materials, scorecard feedback, and media campaign material to review their quality and quantity (refer to the KPIs specified in the MBO framework).
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Primarily, the impact will be computed based on the number of rebate transactions, deemed savings and the content of the TRM. The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.
- There is potential for claiming savings over and above the savings realized by those who will redeem the rebates: that is the savings resulting from incremental sales in LED lighting equipment and automotive heater timers from shoppers influenced by the program but who do not ultimately redeem the rebate. Evaluators refer to commonplace occurrence as ‘spillover’. The approach to estimating these savings involve the following:
  - Consult with the store managers during the finalization of the EM&V plan and confirm their commitment to provide sales data for rebate-eligible products during the 5-year DSM operations window. It is recommended to obtain a detailed commitment; agree on how and when the data will be available and what measures are going to be taken to ensure confidentiality.
  - If the evaluators are successful with the above, then the evaluators will lay out the method to estimate the savings based on the expected data in the final EM&V plan.
- For this program element only, because of the above, and if the evaluators are successful at securing the sales data, the evaluators might choose not to use stipulated NTG ratios. Instead, the evaluators will estimate the spillover ratio based on the sales data and use 1 + Spillover as NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.6 Residential Promotion of Low-Cost Energy Efficient Products

4.6.1 Program Description Summary

The Utilities will prepare and disseminate information on products that generate electricity savings but do not have a perceptible price increment as compared with the baseline equipment. The Utilities will disseminate information through point of purchase displays and brochures in retail stores, and through community engagement. Certain low-cost items will be provided by the Utilities to community volunteers to test and showcase: for example certain LED lamps, low-flow showerheads, faucet aerators, etc. The Utilities will give out a limited number of these items free of charge; volunteers will try them out, fill out a scorecard and send it back. The results will be fed back first to the store managers, and then to the consumers through point of purchase displays and brochures and through community engagement.

Eligible Measures

The preliminary list of low-cost EE products that the Utilities intend to promote includes the items presented in Exhibit 27.

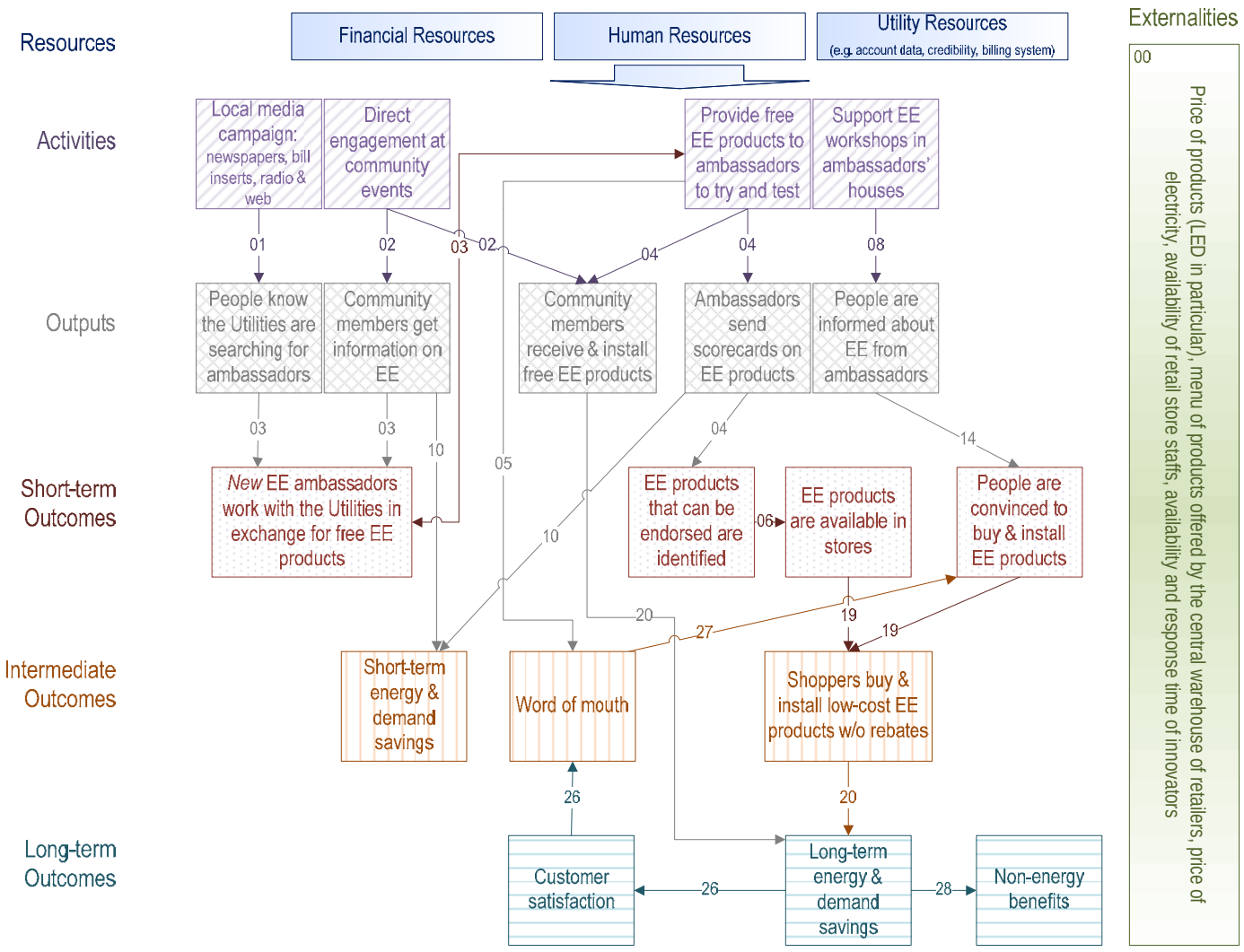
Exhibit 27: List of Energy Conservation Measures Based on Low-cost EE Products

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM242	Pilot 12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	100%	$44.00/unit	20.0 yr	$44.00/unit
ECM602	Pilot 8W LED A19 Bulb	32 kWh/unit	0.011 kW/unit	100%	$31.00/unit	20.0 yr	$31.00/unit
ECM612	Pilot LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	100%	$25.00/unit	20.0 yr	$25.00/unit
ECM622	Pilot LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	100%	$64.00/unit	20.0 yr	$64.00/unit
ECM632	Pilot LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	100%	$53.00/unit	20.0 yr	$53.00/unit
ECM442	Pilot Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	100%	$25.00/unit	10.0 yr	$25.00/unit
ECM092	Pilot Ultra Low-flow Showerheads	325.0 kWh/unit	0.116 kW/unit	100%	$16.01/unit	10.0 yr	$16.01/unit
ECM112	Pilot Smart, Surge Protected Power Bars for PCs and TVs	67.8 kWh/unit	0.024 kW/unit	100%	$50.00/unit	10.0 yr	$50.00/unit
ECM182	Pilot DHW Tank Insulation	62.0 kWh/unit	0.022 kW/unit	100%	$37.58/unit	14.0 yr	$37.58/unit
ECM202	Pilot DHW Pipe Insulation	34.0 kWh/unit	0.012 kW/unit	100%	$0.79/unit	15.0 yr	$0.79/unit
ECM482	Pilot Motion Detectors - Indoor and Outdoor	66.0 kWh/unit	0.024 kW/unit	100%	$22.94/unit	10.0 yr	$22.94/unit
ECM152	Pilot Auto Heater Timers	129.8 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$37.50/unit
ECM142	Pilot Prog. Thermostats (Central)	827.0 kWh/unit	0.295 kW/unit	100%	$62.50/unit	11.0 yr	$62.50/unit
ECM212	Pilot Prog. Thermostats	826.0 kWh/unit	0.295 kW/unit	100%	$285.43/unit	11.0 yr	$285.43/unit
ECM062	Pilot E-Star TVs	69.0 kWh/unit	0.025 kW/unit	100%	$1,125.00/unit	10.0 yr	$1,125.00/unit
ECM082	Pilot ESTAR Printers and Fax	31.7 kWh/unit	0.011 kW/unit	100%	$200.00/unit	6.0 yr	$200/unit
ECM091	Ed. Ultra Low-flow Showerheads	325.0 kWh/unit	0.116 kW/unit	100%	$8.62/unit	10.0 yr	$0/unit
ECM111	Ed. Smart, Surge Protected Power Bars for PCs and TVs	68 kWh/unit	0.024 kW/unit	100%	$25.00/unit	10.0 yr	$0/unit
ECM181	Ed. DHW Tank Insulation	62 kWh/unit	0.022 kW/unit	100%	$37.58/unit	14.0 yr	$0/unit
ECM201	Ed. DHW Pipe Insulation	34.0 kWh/unit	0.012 kW/unit	100%	$0.79/unit	15.0 yr	$0.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 28: Logic Model for the Residential Low-Cost Energy Efficient Products



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, availability of retail store staff, availability and response time of innovators The program administrator should monitor these externalities and adapt the implementation approach based on them.
01	The Utilities will advertise their intention of building an EE community network through the local press, and applicable non-profit and community organizations. It is expected that this tactic will ease the development of the network.
02	The Utilities will carry out outreach activities in community events (eg. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; offer to new home buyers to pilot CCHPs, or GSHPs; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
03	The Utilities will build new relationships and an EE community network that the Utilities will be able to use to extend its communication and community direct engagement footprint.
04	The Utilities will have low-cost EE products tested through volunteers and/or the EE community network. The Utilities will give out a limited number of these items free of charge; the ambassadors will try them out, fill out a simple scorecard and send the scorecard back. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction in other program components such as the LED rebate component, the automotive heater timer rebate component and the low-cost EE product education component.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
06	The consumer responses provided on the scorecards will be aggregated, analyzed and provided to the store managers. The Utilities will be able to endorse certain EE products because customer satisfaction will be good. The results will be presented to the retail store managers, and feed the communication and POP materials. It is expected that store managers will react by stocking more of these products and allocate more shelf space.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, automotive heater timers and innovative heating systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products might have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	It is assumed that shoppers will perceive new non-energy benefits; and/or the maintenance of benefits they used to h baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

4.6.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 28 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 29. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 29 are provided in Section 4.1.2.

Exhibit 29: Management-by-Objective Framework for the Residential Promotion of Low-Cost Energy Efficient Products

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Utilities advertise their request for EE ambassadors	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 2 2 2	 1 1 1	 1 1 1	 1 1 1	 - - -
02	Utilities conduct outreach activities at community events[20]	Suggested KPI(s): # of events w/Program booth # of units of free products given away	Program documentation	 2 522	 4 627	 4 553	 4 532	 2 438
03	Utilities build an EE community network	Suggested KPI(s): # of EE ambassadors	Program documentation	 10	 15	 18	 18	 18
04	EE ambassadors test low-cost EE products[22]	Suggested KPI(s): # of units of free products provided	Program documentation	 20	 45	 54	 54	 54
06	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received EE products that can be endorsed by the Utilities are reviewed and identified (Yes/No)	Direct engagement & communication logs	 10 Yes	 5 Yes	 3 Yes	 2 Yes	 0 Yes
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	 0 8	 2 8	 4 8	 10 8	 0 -
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	-
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-	-

[20] Refer to the Program Design Report Exhibit 77 (Measures referred to as "Pilot")

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
20	The low-cost EE products will yield long-term electricity and demand savings (free products given away to increase the sales)	MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	1,064 91 32	1,667 237 84	1,454 362 129	1,141 460 164	928 538 192
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback1-to-10 scale, level of satisfaction with the products	Tracking System	7/10	7/10	7/10	7/10	-
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Utilities advertise their request for EE ambassadors	Suggested indicator(s): % EE ambassadors that heard about the opportunity through media / email / bill insert	EE ambassadors			80%		80%
02	Utilities conduct outreach activities at community events	No evaluation indicator	-			-		-
03	Utilities build an EE community network	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the EE ambassador network	EE ambassadors			7/10		7/10
04	EE ambassadors test low-cost EE products	No evaluation indicator	-			-		-
06	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation			70%		70%
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
14 & 19	Shoppers buy and install low-cost EE products[21]	Suggested indicator(s): # units sold	Retail store sales info (if available)	425	1,089	1,119	1,169	1,179
20	The low-cost EE products will yield long-term electricity and demand savings (increased sales achieved through education)	KPIs to be verified by evaluators. Suggested indicator(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Retail store sales info (if available)	785 78 28	2,302 306 109	2,218 533 190	2,399 776 277	2,413 1,020 364
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program 1-to-10 scale, level of satisfaction with their energy efficient products	Participants Participants			8/10 7/10		8/10 7/10

[21] Refer to the Program Design Report Exhibit 78 (Measures referred to as "Ed.")

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		60% 30%
28	Non-energy benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the low cost EE product quality	Participants			9/10		9/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential Promotion of Low-Cost Energy Efficient Products. In addition, the following question will be explored:

- How effective are rebates, POP material, direct engagement at community events, and through the EE community network at increasing the sales of the low-cost EE products?
- How willing/able are retail store managers to share sales data to monitor the impact of the program?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential Promotion of Low-cost Energy Efficient Products* have implications on the evaluation methods employed:

- The Utilities will distribute many EE products free of charge (e.g. low-flow showerhead, faucet aerators, DHW tank insulation, DHW pipe insulation, etc.); and these alone will generate savings.
- This program element will promote the increase of market penetration and sales of low-cost energy efficient products as compare with “base” products. These incremental sales will generate significant impacts, much larger than that for the giveaways alone.
- None of the products will realize savings per building of over 10% of the total building electricity consumption, therefore utility billing analysis or whole-building M&V will not be an option.
- Site visit or field measurement campaign will not be practical for a jurisdiction of the size of Yukon. Hence it is recommended to follow a deemed savings approach and to use a TRM.
- Primarily, the impact will be computed based on the number of free low-cost EE products distributed. But the impact is not expected to be bound to the giveaways only. The evaluators will have to establish how the marketing, education, communication and the giveaways influenced the sales and increased the penetration of the targeted electricity efficient products.

- In addition, the education provided to Yukon residents as part of the direct community engagement activities will influence their behavior and may cause them to reduce their peak demand and electricity use. However, quantifying behavior-based electricity and demand savings is will not be estimated.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: retail store managers (p≈20), landlords (p≈50), shoppers (p≈20,000), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews with retail store managers, EE ambassadors, and phone or online surveys with participants and non-participants, but evaluators will be able to suggest an alternative approach if necessary. Mystery shoppers and retail intercepts might also be considered. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the community event booth materials, scorecard feedback, and media campaign material to review their quality and quantity (refer to the KPIs specified in the MBO framework).
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact evaluation for this program element needs to be carried out by monitoring the sales of low-cost electricity efficient products and their respective base cases. Therefore, it is critical to:
    - Consult with the store managers during the finalization of the EM&V plan and confirm their commitment to provide sales data for identified low-cost EE products during the 5-year DSM operations window. It is recommended to obtain a detailed commitment; agree on how and when the data will be available and what measures are going to be taken to ensure confidentiality.
    - If the evaluators are successful with the above, then the evaluators will lay out the method to estimate the savings based on the expected data in the final EM&V plan.
- Evaluators will estimate the incremental sales of EE products; then turn these figures and the number of giveaways in savings estimates using the program portfolio TRM.
- The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.7 Residential GSHP & CCHP Initiative

4.7.1 Program Description Summary

The Utilities will pilot cold climate heat pumps (CCHPs) and ground-source heat pumps (GSHPs). The pilot systems will be subsidized, not provided free of charge, and the results will be disseminated through different channels, such as HVAC contractors, electrical contractors, housing developers and municipalities.

After the completion of these pilot projects, the Utilities will provide a flat amount of money to buyers of new houses or condominium units if they buy a home with a cold climate heat pump (CCHP) or a ground-source heat pump (GSHP) system, or to owners of homes with electric central air heating systems to retrofit their home with a CCHP or a GSHP.

Eligible Measures

The preliminary list of technologies that the Utilities intend to promote includes the items presented in Exhibit 30.

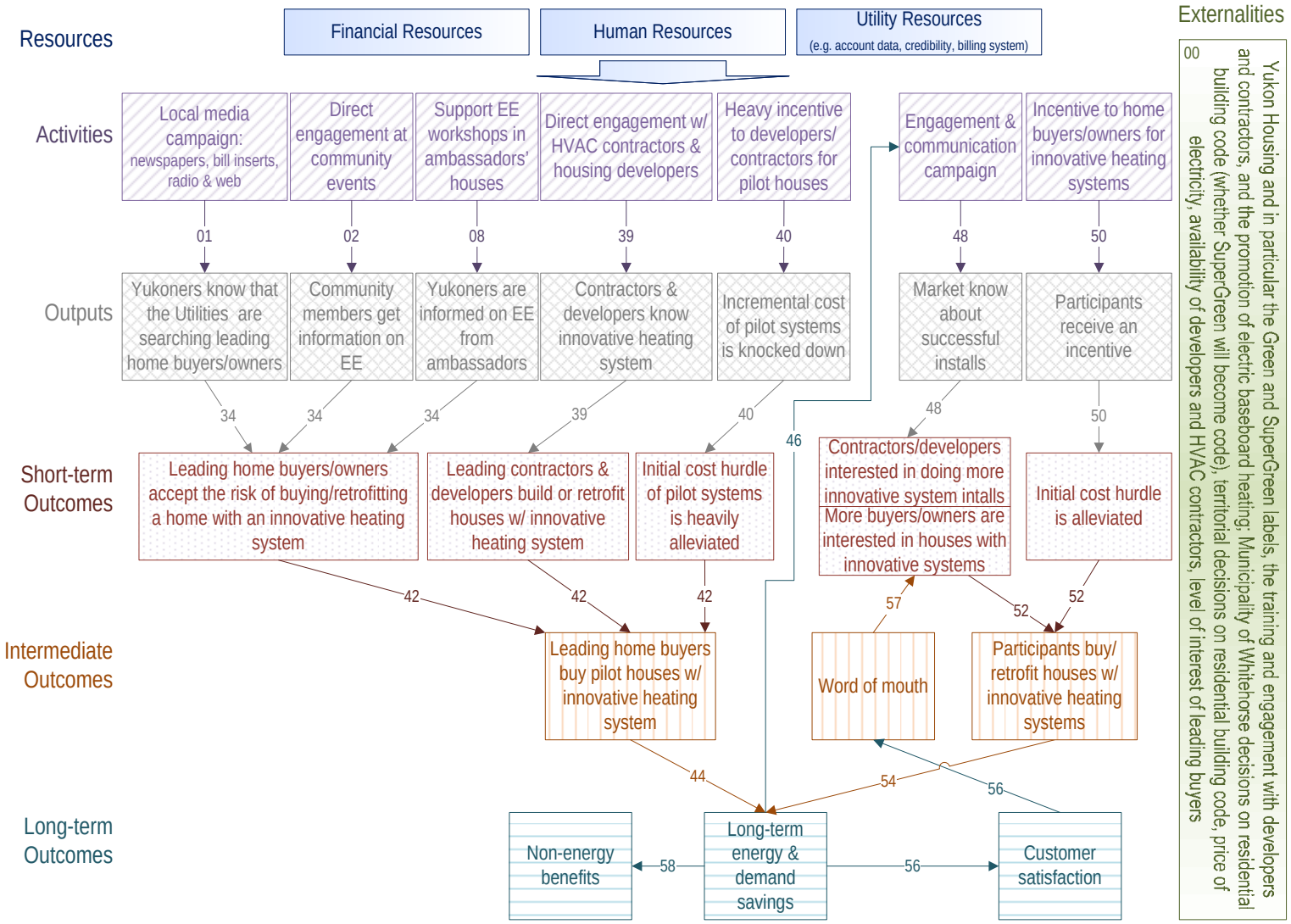
Exhibit 30: Inputs and Assumptions of Residential New-Construction GSHP and CCHP Initiative

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM032	Pilot Cold Temp Heat Pumps	6,780 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$5,000.00/unit
ECM372	Pilot Ground Heat Pumps - Closed	8,605 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$9,000.00/unit
ECM03	Cold Temp Heat Pumps	6,780.0 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$2,500.00/unit
ECM37	Ground Heat Pumps - Closed	8,605.0 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$3,500.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 31: Logic Model for the Residential GSHP and CCHP Initiative



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: Yukon Housing, in particular the Green and SuperGreen labels, the training and engagement with developers and contractors, and the promotion of electric baseboard heating; Municipality of Whitehorse decisions on residential building code (whether SuperGreen will become code); territorial decisions on residential building code; price of electricity; availability of developers and HVAC contractors and level of interest of leading buyers. The program administrator should monitor these externalities and adapt the implementation approach accordingly.
01	The Utilities will advertise their intention to build an EE community network through the local press and applicable non-profit and community organizations. It is expected that this tactic will ease the development of the network.

Link #	Narrative
02	The Utilities will carry out outreach activities in community events (e.g., sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; offer to new home buyers to pilot CCHPs or GSHPs; and promote the idea of supporting a EE workshop at their home or a at local venue.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and innovative heating systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
34	Through community direct engagement tactics as detailed in links #01, #02 & #03, the Utilities will find leading home buyers or leading home owners who will accept the risk of buying a home with an innovative heating system.
39	The Utilities will engage directly with all of the HVAC contractors and housing developers in the Yukon. Because there only a few, it is realistic to speak with all of them. The Utilities will find leading developers and HVAC contractors who are willing take on the risk of building houses with innovative heating systems; or to retrofit existing homes with CCHP and GSHP systems. Their risk exposure will be reduced because the Utilities will help them find clients.
40	The Utilities will provide an incentive to the developers and contractors that will significantly reduce the total incremental cost of the technologies: not only the cost of the heat pump and the bore wells, but also the cost of the central air ductwork. The initial-cost hurdle of pilot houses will be heavily alleviated.
42	Developers will build pilot houses with innovative heating systems; and new home buyers will buy them because the Utilities will have found the buyers, matched them with the developers/contractors, and heavily subsidized the projects to address the initial-cost hurdle. Alternatively, innovative contractors will retrofit existing homes with innovative heating systems. The home owners will be willing to have their house pilot the system because the Utilities will have found leading home owners, matched them with innovative contractors, and heavily subsidized the projects to address the initial-cost hurdle.
44	The pilot houses with innovative heating systems will yield long-term electricity and demand savings. This electricity and demand savings will be verified and documented through state-of-the art project performance measurement and verification (M&V) activities.
46	The results of the pilot projects and of the M&V activities will feed the program planning; and will feed the engagement and communication campaign of the CCHP and GSHP incentive program component.
48	The Utilities deliver an engagement and communication campaign primarily through already-established channels: community direct engagement; and HVAC contractors and developers engagement. In addition, the Utilities will launch a local media campaign through local newspapers, local radios, brochures to be passed to prospective buyers by developers and contractors, email blasts, bill inserts and web content development. The Utilities will publicize the results of the pilot projects so that the market knows that the installations were successful and that CCHP and GSHP are viable technologies in the Yukon. As a result, developers and contractors will be interested in doing more CCHP and GSHP system installations, more home buyers will be interested in houses with these heating systems; and more home owners will be interested in retrofitting their houses with CCHP and GSHP systems.
50	The Utilities will provide a flat amount of money adjusted based on the capacity of the CCHP or the GSHP (per tons of refrigeration) installed and attributed to buyers of new houses or condominium units heated with a CCHP or a GSHP system; or to home owners willing to retrofit their houses with a CCHP or a GSHP system. The incentive level of CCHP and GSHP will differ. The incentive will alleviate the initial cost hurdle of CCHP and GSHP systems.
52	Because the supply and the demand will be stimulated, and because the initial-cost hurdle is alleviated, the participating home buyers or home owners (the participants) will buy houses with CCHP or GSHP systems.

Link #	Narrative
54	The houses of participants in the CCHP and GSHP incentive program component will yield long-term electricity and demand savings.
56	Participants will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
57	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy new houses with CCHP or GSHP systems; or to retrofit their houses with CCHP or GSHP systems.
58	It is assumed that the participants (pilot projects and incentive) will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. The Utilities will seek to see the participants perceive that the comfort provided by CCHPs, and GSHPs is equivalent to what would be provided by baseboards heating.

4.7.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 31 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 32. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 32 are provided in Section 4.1.2.

Exhibit 32: Management-by-Objective Framework for the Residential GSHP & CCHP Initiative

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Utilities advertise their request for EE ambassadors	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 2 2 2	 1 1 1	 1 1 1	 1 1 1	 - - -
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth	Program documentation	2	1	1	1	1
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	0 8	1 8	1 8	1 8	0 -
34	Utilities identify leading home owners/buyers	Suggested KPI(s): # of leading home owners	Program documentation	1	1	1	1	-
39	Direct engagement with HVAC contractors and housing developers	Suggested KPI(s): # of HVAC contractors and developers contacted	Direct engagement & comm. logs	18	18	-	-	-
40 & 42	Utilities provide incentive for GSHP and CCHP pilot projects[22]	$ of incentive disbursement for pilot projects	Tracking System	$5K	$9K	$5K	$0	-

[22] Refer to Program Design Report Exhibit 84

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
46	Results of the pilot projects inform the innovative heating system incentive	No associated tracked KPIs	-	-	-	-	-	-
48	Utilities publicize results of the pilot projects	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 - - -	 - - -	 - - -	 2 1 1	 2 1 1
50	Utilities provide incentive for innovative heating systems[23]	$ of incentive disbursement for innovative heating systems	Tracking System	$0	$0	$0	$19K	$19K
52	Home owners/managers agree to purchase innovative heating systems[24]	# of transactions in the innovative heating system incentive	Tracking System	-	-	-	7	7
44 & 54	The GSHP and CCHP pilot projects will yield long-term electricity and demand savings[25]	MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	148 7 3	188 17 6	188 26 9	1,223 87 31	1,075 141 50
57	Participants will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed in under 10 business days	Tracking System	-	-	80%	80%	80%
56	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
58	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Utilities advertise their request for EE ambassadors	Suggested indicator(s): % EE ambassadors that heard about the opportunity through media / email / bill insert	EE ambassadors			80%		80%
02	Utilities conduct outreach activities at community events	No evaluation indicator	-			-		-
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
34	Utilities identify leading home owners/buyers	No evaluation indicator	-			-		-
39	Direct engagement with HVAC contractors and housing developers	Suggested indicator(s): % HVAC contractors and developers who know the program	HVAC contractors and developers			90%		100%

[23] Refer to Program Design Report Exhibit 85
[24] Refer to Program Design Report Exhibit 84
[25] Refer to the Program Design Report Exhibit 86

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
40 & 42	Utilities provide incentive for pilot projects[26]	Suggested indicator(s): % HVAC contractors/developers (that did not participate in the pilot projects) that heard about the results	Non-participants			80%		80%
46	Results of the pilot projects inform the innovative heating system incentive	Suggested indicator(s): Yes/No pilot project results provided ground to proceed with a full-fledge incentive program for innovative heating system in Yukon	Program documentation			Yes		
48	Utilities publicize results of the pilot projects	Suggested indicator(s): % HVAC contractors/developers (that did not participate in the pilot projects) that heard about the results	Non-participants					100%
50	Utilities provide incentive for innovative heating systems[27]	Suggested indicator(s): % of participants who agree that the incentive got them to install a more sophisticated heating system then they would have otherwise	Participants					60%
		% of participating suppliers who confirm the above	Supply-chain actors					60%
52	Home owners/managers agree to purchase innovative heating systems[28]	No evaluation indicator	-			-		-
44 & 54	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
57	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient products	Participants			7/10		7/10
56	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
58	Non-energy benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with interior comfort provided	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the level of effort and cost to maintain the system				8/10		8/10

[26] Refer to Program Design Report Exhibit 84
[27] Refer to Program Design Report Exhibit 85
[28] Refer to Program Design Report Exhibit 84

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential CCHP and GSHP Initiative. In addition, the following question will be explored:

- Based on the pilot projects, should the Utilities proceed with a full-fledged incentive program for CCHP and/or GSHP?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential GSHP & CCHP Initiative* have implications on the evaluation methods employed:

- Relatively few projects are anticipated (4 pilot projects and 14 incentive projects), therefore transactional infrastructure will be rudimentary and documentation will be on a project-by-project basis.
- An aggregate of the project-level M&V results of each of the pilot projects can be fed into the program-level evaluation.
- The later incentive-eligible projects will be few (14 projects are estimated). Thus, it is recommended to have the inCharge staff (for example: the YEC Energy Conservation Coordinator) use the same M&V method as were used for the pilot projects.
- The pilot projects are planned to be implemented between Y1-Q4 and Y3-Q2, and thus the post-retrofit measurement period – expected to last for one year – is to end between Y2-Q4 and Y3-Q3.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: HVAC/control designers and contractors (p≈18), property managers (p≈8 large), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the technical assistance reports provided to participants to assess soundness of calculations and the proposed solutions.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact of this program element will be evaluated based on the aggregated results of all of the project-level M&V reports completed for each of the pilot projects and for each of the later projects. The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of

utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days. Please refer to Section 3.2 for additional details.

- Since the M&V estimates for the later projects are going to be made by inCharge staff, the evaluators are to carry out a desk review of these calculations.
- GSHP & CCHP systems are very new in Yukon, thus there will be very few distortion effects. Consequently it is recommended to use a stipulated NTG ratio of 1.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

5. Procurement of Third-Party Evaluation Services

The Utilities intend to select one independent EM&V contractor through a competitive tendering process who will evaluate both the General Service Program and the Residential Program. A committee of staff from both Utilities will select the contractor. The following observations are provided for consideration by the Utilities in this procurement process.

- Potential bidders can be identified through the International Energy Program Evaluation Conference (IEPEC) as most active North-American evaluators participate in this bi-annual conference. Their names will appear among the sponsors and in the conference proceedings.
- DSM evaluation contractors are usually multi-disciplinary teams with capabilities in social science research, marketing, energy policy, economics, statistics, energy analytics, energy engineering and project-level M&V. It is good for an evaluation contractor to have Certified Measurement and Verification Professionals (CMVP) among the team.
- Some Utilities employ a two-step procurement process. The first step is to submit a Request for Qualifications (RFQ). Qualifying firms would be placed on a short list of two to five bidders. Creating a short-list of bidders has the following benefits:
  - Reduces the level of effort required by the selection committee.
  - Limits the dissemination of information about the program – some that might be confidential – to fewer companies.
  - Tends to increase the response rate and overall proposal quality as the respondents know that they are bidding against a smaller, select number of competitors.
- It is standard practice to share program information with the evaluation bidders. If desirable, the information can be shared on a confidential basis. Increasing the information that is shared before the bid will allow the evaluators to prepare proposals with a greater level of detail.
- This EM&V plan can also serve as an information package for the bidders. If it is not possible to share the EM&V plan with the bidders, then it is suggested that the Utilities include the following items in their request for proposals:
  - The scale of the program in terms of impact and budget. This will allow bidders to estimate the level of effort, to decide on the preferable level of rigor, and to get a general feel for the total evaluation budget.
  - The applicable evaluation best practices (See section 2.5). This would help standardize the terminology among proposals.
  - The program documentation that will be available to them early after signing the EM&V contract. Knowing what pieces of documentation and information exist will make bidders appreciate the professionalism of the approach. This should reduce their perception of risk and in turn increase the number of serious contenders.[29]

[29] The Utilities could inform bidders about the availability of the following information: an EM&V plan; a CPR report; market characterization reports; program design document; PIP and Year-1 program startup progress reports; program theory, logic models, KPIs and targets; program tracking system and program database; the deemed-savings estimates, an ex-ante cost-effectiveness model, and a draft technical reference manual; and, draft with site verifications protocols for use by DSM staff on a routine basis.

- Bidders should be allowed to propose methods that are different from those in the current EM&V plan, if they deem it appropriate. This approach will allow the Yukon stakeholders to tap into the creativity of a larger pool of methodologists.
- The bidders should be asked to present a list of data that they plan to collect, either as part of the proposal or during the inception of the EM&V work. Typically, these data are presented as a table of researchable issues.

YUB-YECL-27

Reference: Allocation of promotional and educational costs, Yukon Five Year Demand Side Management Plan, page 14

Benefit/Cost results are not calculated for program elements that are promotional or educational in nature; however, their associated costs are captured and distributed among those program elements that do create electricity savings.

The Board wants to better understand how these promotional or educational costs will be allocated among the different programs.

Request:

Please describe the methodology that YEC and YECL used to decide how much of the promotional or educational costs are allocated to each program.

Response:

In the model used to design the programs, these costs are allocated to the residential or the general service segment using bottom-up budgetary estimates. These costs are not allocated to the direct-impact program elements. Program administration costs are accounted for in the non-incentive level costs per measure and can be found in the *DSM Program Incentive Level Justification*, provided as YUB-YECL-27 Attachment 1.

Appendix D Incentive Level Justification

Energy Conservation Measure - Justification of the Incentive Level

The purpose of this worksheet is to explain the metholodogy used to calculate the incentive levels for measures in the General Service Program requiring an alternative approach compared to the the one used for the other measures in the Program portfolio.

Redesign Measures

ECM91	Lighting Resdeign Study
ECM912	Gov. Lighting Redesign Study

The incentive levels for the resdesign measures were computed using a trial and error method. Because there are no savings associated with these measures, the cost effectiveness results were computed at the program level instead of at the individual measure level.

Lighting Measures

ECM80	Typical Lighting Project in Existing Bldg - Office
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel
ECM86	Typical Lighting Project in Existing Bldg - Restaurant
ECM87	Typical Lighting Project in Existing Bldg - Recreation
ECM88	Typical Lighting Project in Existing Bldg - Warehouse
ECM92	Commercial 12W LED A19 Bulb
ECM93	Commercial 8W LED A19 Bulb
ECM94	Commercial LED MR16 Bulbs
ECM95	Commercial LED PAR30 Bulbs
ECM96	Commercial LED PAR38 Bulbs
ECM97	Commercial Spot or task lighting
ECM802	Gov. Typical Lighting Project in Existing Bldg - Office
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse
ECM922	Gov. Commercial 12W LED A19 Bulb
ECM932	Gov. Commercial 8W LED A19 Bulb
ECM942	Gov. Commercial LED MR16 Bulbs
ECM952	Gov. Commercial LED PAR30 Bulbs
ECM962	Gov. Commercial LED PAR38 Bulbs
ECM972	Gov. Commercial Spot or task lighting

The total lighting incentive is made up of a custom portion and a prescriptive portion. The custom incentive provides flexibility in the choice of lighting technologies and also encourages contractors and designers to be innovative. The custom incentive was calculated using a dollar value per annual kilowatt hour of savings. This value was established using a trial and error procedure and evaluation of the cost-effectiveness results on the program-element level. The purpose of the prescriptive incentive is to increase the incentive total if LED lamps are used, since the initial-cost hurdle is higher for LED technologies than for other technoclogies. The prescriptive incentive also aims to accelerate the market penetration of LEDs. The prescriptive lighting incentive levels in the General Service Program are idential to those in the Residential Program.

Due to limitations of the model, it was not possible to compute the cost-effectiveness test results for the lighting measures on a measure by measure basis. However, the model did allow for the accurate calculation of the cost-effectiveness test results for these measures on the program level.

Energy Conservation Measure - Justification of the Incentive Level

ECM98

Inputs - Measure Considerations	
Measure Name: Typical Low-Cost No-Cost Refrigeration Project - Food Retail	
Incentive Amount:	$1.31/ft2
Measure/Project Cost:	$1.73/ft2
Gross Consumption Savings:	6.6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7.1 kWh/ft2/yr
Gross Demand Savings:	.00074 kW/ft2
Gross Demand Savings w/ T&D losses:	.00081 kW/ft2
Participant's Savings on Year 1:	$1.13/ft2
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	90%
Suggested Program Cost (% of Incentive):	90%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	6.04
PC - Net Present Value	$8.70
PC - Levelized Cost	$0.0354/kWh
Simple Payback w/ Incentive (yr)	0.4 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$0.32*
RIM - Levelized Cost	*$0.2209/kWh*
TRC - Benefit/Cost Ratio	4.07
TRC - Net Present Value	$8.65
TRC - Levelized Cost	$0.0558/kWh
PAC - Benefit/Cost Ratio	*4.61*
PAC - Net Present Value	*$8.98*
PAC - Levelized Cost	*$0.0493/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$3.96*
RIM-YECL - Levelized Cost	*$0.1713/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.56*
RIM-YEC - Net Present Value	*$3.82*
RIM-YEC - Levelized Cost	*$0.1299/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$1.73
Incentive Amount in Year 1	$1.31
Assumed Program Administration Costs in Year 1	$1.18
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$9.11	$9.11
Discounted Cumulative Gross Energy Savings for 10 years	49 kWh	49 kWh
PC - Present Value of Benefits	$10.42	$10.42
PC - Present Value of Costs	$1.73	$1.73
PC - Benefit/Cost Ratio	6.04	6.04
PC - Net Present Value	$8.70	$8.70
PC - Levelized Cost	$0.0354/kWh	$0.0354/kWh
Simple Payback with Incentive	0.4 yr	0.4 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$8.66	$8.66
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
RIM - Present Value of Benefits	$11.47	$11.47
RIM - Present Value of Costs	$11.15	$9.97
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.32	$1.50
RIM - Levelized Cost	$0 2209/kWh	$0.1976/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
TRC - Present Value of Benefits	$11.47	$11.47
TRC - Present Value of Costs	$2.82	$1.64
TRC - Benefit/Cost Ratio	4.07	7.0
TRC - Net Present Value	$8.65	$9.83
TRC - Levelized Cost	$0.0558/kWh	$0.0325/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
PAC - Present Value of Benefits	$11.47	$11.47
PAC - Present Value of Costs	$2.49	$1.31
PAC - Benefit/Cost Ratio	4.6	8.8
PAC - Net Present Value	$8.98	$10.16
PAC - Levelized Cost	$0.0493/kWh	$0.0260/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM99

Inputs - Measure Considerations	
Measure Name:	Typical Deep Retrofit Refrigeration Project - Food Retail
Incentive Amount:	$2.70/ft2
Measure/Project Cost:	$5.87/ft2
Gross Consumption Savings:	13.5 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	14.7 kWh/ft2/yr
Gross Demand Savings:	.00153 kW/ft2
Gross Demand Savings w/ T&D losses:	.00167 kW/ft2
Participant's Savings on Year 1:	$2.33/ft2
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	90%
Suggested Program Cost (% of Incentive):	90%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.66
PC - Net Present Value	$15.58
PC - Levelized Cost	$0.0585/kWh
Simple Payback w/ Incentive (yr)	1.4 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$0.66*
RIM - Levelized Cost	*$0.2209/kWh*
TRC - Benefit/Cost Ratio	2.95
TRC - Net Present Value	$15.60
TRC - Levelized Cost	$0.0770/kWh
PAC - Benefit/Cost Ratio	*4.61*
PAC - Net Present Value	*$18.48*
PAC - Levelized Cost	*$0.0493/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$8.14*
RIM-YECL - Levelized Cost	*$0.1713/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.56*
RIM-YEC - Net Present Value	*$7.86*
RIM-YEC - Levelized Cost	*$0.1299/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$5.87
Incentive Amount in Year 1	$2.70
Assumed Program Administration Costs in Year 1	$2.42
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$18.75	$18.75
Discounted Cumulative Gross Energy Savings for 10 years	100 kWh	100 kWh
PC - Present Value of Benefits	$21.45	$21.45
PC - Present Value of Costs	$5.87	$5.87
PC - Benefit/Cost Ratio	3.66	3.66
PC - Net Present Value	$15.58	$15.58
PC - Levelized Cost	$0.0585/kWh	$0.0585/kWh
Simple Payback with Incentive	1.4 yr	1.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$17.82	$17.82
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
RIM - Present Value of Benefits	$23.60	$23.60
RIM - Present Value of Costs	$22.93	$20.51
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.66	$3.09
RIM - Levelized Cost	$0 2209/kWh	$0.1976/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
TRC - Present Value of Benefits	$23.60	$23.60
TRC - Present Value of Costs	$7.99	$5.57
TRC - Benefit/Cost Ratio	2.95	4 2
TRC - Net Present Value	$15.60	$18.03
TRC - Levelized Cost	$0.0770/kWh	$0.0537/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
PAC - Present Value of Benefits	$23.60	$23.60
PAC - Present Value of Costs	$5.12	$2.70
PAC - Benefit/Cost Ratio	4.6	8.8
PAC - Net Present Value	$18.48	$20.90
PAC - Levelized Cost	$0.0493/kWh	$0.0260/kWh

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Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1002

Inputs - Measure Considerations

Measure Name:	Typical Refrigeration Project - Ice Rink
Incentive Amount:	$0.40/ft2
Measure/Project Cost:	$0.72/ft2
Gross Consumption Savings:	2.5 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	2.7 kWh/ft2/yr
Gross Demand Savings:	.00034 kW/ft2
Gross Demand Savings w/ T&D losses:	.00037 kW/ft2
Participant's Savings on Year 1:	$0.43/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	111%
Suggested Program Cost (% of Incentive):	111%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	10.01
PC - Net Present Value	$6.50
PC - Levelized Cost	$0.0261/kWh
Simple Payback w/ Incentive (yr)	0.7 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$0.33*
RIM - Levelized Cost	*$0.2553/kWh*
TRC - Benefit/Cost Ratio	6.20
TRC - Net Present Value	$5.87
TRC - Levelized Cost	$0.0393/kWh
PAC - Benefit/Cost Ratio	*8.31*
PAC - Net Present Value	*$6.15*
PAC - Levelized Cost	*$0.0294/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$3.43*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*2.11*
RIM-YEC - Net Present Value	*$4.00*
RIM-YEC - Levelized Cost	*$0.1161/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.72
Incentive Amount in Year 1	$0.40
Assumed Program Administration Costs in Year 1	$0.44
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$6.82	$6.82
Discounted Cumulative Gross Energy Savings for 20 years	28 kWh	28 kWh
PC - Present Value of Benefits	$7.22	$7.22
PC - Present Value of Costs	$0.72	$0.72
PC - Benefit/Cost Ratio	10.01	10.01
PC - Net Present Value	$6.50	$6.50
PC - Levelized Cost	$0.0261/kWh	$0.0261/kWh
Simple Payback with Incentive	0.7 yr	0.7 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$6.48	$6.48
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
RIM - Present Value of Benefits	$7.00	$7.00
RIM - Present Value of Costs	$7.33	$6.88
RIM - Benefit/Cost Ratio	1.0	1.0
RIM - Net Present Value	-$0.33	$0.11
RIM - Levelized Cost	$0 2553/kWh	$0.2398/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
TRC - Present Value of Benefits	$7.00	$7.00
TRC - Present Value of Costs	$1.13	$0.69
TRC - Benefit/Cost Ratio	6.20	10 2
TRC - Net Present Value	$5.87	$6.31
TRC - Levelized Cost	$0.0393/kWh	$0.0239/kWh

Program Administrator Cost Test from YEC Perspective (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
PAC - Present Value of Benefits	$7.00	$7.00
PAC - Present Value of Costs	$0.84	$0.40
PAC - Benefit/Cost Ratio	8.3	17 5
PAC - Net Present Value	$6.15	$6.60
PAC - Levelized Cost	$0.0294/kWh	$0.0139/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM101

Inputs - Measure Considerations	
Measure Name:	ES Desktop Computer and Monitor
Incentive Amount:	$30.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	148 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	161 kWh/yr
Gross Demand Savings:	0.03 kW
Gross Demand Savings w/ T&D losses:	0.03 kW
Participant's Savings on Year 1:	$25.59
Measure Lifetime:	4 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	211%
Suggested Program Cost (% of Incentive):	211%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	*
PC - Net Present Value	$125.01
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-1.2 yr
RIM - Benefit/Cost Ratio	*0.65*
RIM - Net Present Value	*-$64.08*
RIM - Levelized Cost	*$0.3318/kWh*
TRC - Benefit/Cost Ratio	1.89
TRC - Net Present Value	$56.18
TRC - Levelized Cost	$0.1145/kWh
PAC - Benefit/Cost Ratio	*1.28*
PAC - Net Present Value	*$26.18*
PAC - Levelized Cost	*$0.1687/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$42.38*
RIM-YECL - Levelized Cost	*$0.1630/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.14*
RIM-YEC - Net Present Value	*$19.73*
RIM-YEC - Levelized Cost	*$0.2446/kWh*

Reference Data from Other Jurisdictions:

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$30.00
Assumed Program Administration Costs in Year 1	$63.38
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$95.01	$95.01
Discounted Cumulative Gross Energy Savings for 4 years	534 kWh	534 kWh
PC - Present Value of Benefits	$125.01	$125.01
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$125.01	$125.01
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-1 2 yr	-1.2 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$90.26	$90.26
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
RIM - Present Value of Benefits	$119.56	$119.56
RIM - Present Value of Costs	$183.64	$120.26
RIM - Benefit/Cost Ratio	0.7	1.0
RIM - Net Present Value	-$64.08	-$0.70
RIM - Levelized Cost	$0 3318/kWh	$0.2173/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
TRC - Present Value of Benefits	$119.56	$119.56
TRC - Present Value of Costs	$63.38	$0.00
TRC - Benefit/Cost Ratio	1.89	*
TRC - Net Present Value	$56.18	$119.56
TRC - Levelized Cost	$0.1145/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
PAC - Present Value of Benefits	$119.56	$119.56
PAC - Present Value of Costs	$93.38	$30.00
PAC - Benefit/Cost Ratio	1.3	4.0
PAC - Net Present Value	$26.18	$89.56
PAC - Levelized Cost	$0.1687/kWh	$0.0542/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM102

Inputs - Measure Considerations	
Measure Name:	ES Laptop Computer
Incentive Amount:	$10.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	41 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	45 kWh/yr
Gross Demand Savings:	0.01 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$7.09
Measure Lifetime:	4 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	211%
Suggested Program Cost (% of Incentive):	211%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	*
PC - Net Present Value	$36.32
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-1.4 yr
RIM - Benefit/Cost Ratio	*0.59*
RIM - Net Present Value	*-$23.01*
RIM - Levelized Cost	*$0.3661/kWh*
TRC - Benefit/Cost Ratio	1.57
TRC - Net Present Value	$12.00
TRC - Levelized Cost	$0.1378/kWh
PAC - Benefit/Cost Ratio	*1.06*
PAC - Net Present Value	*$2.00*
PAC - Levelized Cost	*$0.2030/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$11.74*
RIM-YECL - Levelized Cost	*$0.1630/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.00*
RIM-YEC - Net Present Value	*$0.21*
RIM-YEC - Levelized Cost	*$0.2784/kWh*

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$21.13
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$26.32	$26.32
Discounted Cumulative Gross Energy Savings for 4 years	148 kWh	148 kWh
PC - Present Value of Benefits	$36.32	$36.32
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$36.32	$36.32
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-1.4 yr	-1.4 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$25.00	$25.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
RIM - Present Value of Benefits	$33.12	$33.12
RIM - Present Value of Costs	$56.13	$35.00
RIM - Benefit/Cost Ratio	0.6	0 9
RIM - Net Present Value	-$23.01	-$1.88
RIM - Levelized Cost	$0 3661/kWh	$0.2283/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
TRC - Present Value of Benefits	$33.12	$33.12
TRC - Present Value of Costs	$21.13	$0.00
TRC - Benefit/Cost Ratio	1.57	*
TRC - Net Present Value	$12.00	$33.12
TRC - Levelized Cost	$0.1378/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
PAC - Present Value of Benefits	$33.12	$33.12
PAC - Present Value of Costs	$31.13	$10.00
PAC - Benefit/Cost Ratio	1.1	3 3
PAC - Net Present Value	$2.00	$23.12
PAC - Levelized Cost	$0 2030/kWh	$0.0652/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1012

Inputs - Measure Considerations

Measure Name:	Gov. ES Desktop Computer and Monitor
Incentive Amount:	$18.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	148 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	161 kWh/yr
Gross Demand Savings:	0.03 kW
Gross Demand Savings w/ T&D losses:	0.03 kW
Participant's Savings on Year 1:	$31.41
Measure Lifetime:	4 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	189%
Suggested Program Cost (% of Incentive):	189%
Forecasted Freeridership:	50%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	*
PC - Net Present Value	$134.62
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-0.6 yr
RIM - Benefit/Cost Ratio	*0.60*
RIM - Net Present Value	*-$46.89*
RIM - Levelized Cost	*$0.3623/kWh*
TRC - Benefit/Cost Ratio	2.04
TRC - Net Present Value	$35.25
TRC - Levelized Cost	$0.1060/kWh
PAC - Benefit/Cost Ratio	*1.33*
PAC - Net Present Value	*$17.25*
PAC - Levelized Cost	*$0.1622/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$36.24*
RIM-YECL - Levelized Cost	*$0.2001/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.91*
RIM-YEC - Net Present Value	*-$7.18*
RIM-YEC - Levelized Cost	*$0.2381/kWh*

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$18.00
Assumed Program Administration Costs in Year 1	$33.97
Assumed Net-to-gross Ratio	55%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$116.62	$116.62
Discounted Cumulative Gross Energy Savings for 4 years	534 kWh	534 kWh
PC - Present Value of Benefits	$134.62	$134.62
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$134.62	$134.62
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-0.6 yr	-0.6 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test from YEC Perspective (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$64.14	$64.14
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
RIM - Present Value of Benefits	$69.22	$69.22
RIM - Present Value of Costs	$116.11	$82.14
RIM - Benefit/Cost Ratio	0.6	0.8
RIM - Net Present Value	-$46.89	-$12.92
RIM - Levelized Cost	$0 3623/kWh	$0.2563/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
TRC - Present Value of Benefits	$69.22	$69.22
TRC - Present Value of Costs	$33.97	$0.00
TRC - Benefit/Cost Ratio	2.04	*
TRC - Net Present Value	$35.25	$69.22
TRC - Levelized Cost	$0.1060/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test from YEC Perspective (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
PAC - Present Value of Benefits	$69.22	$69.22
PAC - Present Value of Costs	$51.97	$18.00
PAC - Benefit/Cost Ratio	1.3	3.8
PAC - Net Present Value	$17.25	$51.22
PAC - Levelized Cost	$0.1622/kWh	$0.0562/kWh

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Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1022

Inputs - Measure Considerations

Measure Name:	Gov. ES Laptop Computer
Incentive Amount:	$6.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	41 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	45 kWh/yr
Gross Demand Savings:	0.01 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$8.70
Measure Lifetime:	4 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	189%
Suggested Program Cost (% of Incentive):	189%
Forecasted Freeridership:	50%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	*
PC - Net Present Value	$38.31
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-0.7 yr
RIM - Benefit/Cost Ratio	*0.55*
RIM - Net Present Value	*-$15.92*
RIM - Levelized Cost	*$0.3953/kWh*
TRC - Benefit/Cost Ratio	1.69
TRC - Net Present Value	$7.85
TRC - Levelized Cost	$0.1276/kWh
PAC - Benefit/Cost Ratio	*1.11*
PAC - Net Present Value	*$1.85*
PAC - Levelized Cost	*$0.1951/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$10.04*
RIM-YECL - Levelized Cost	*$0.2001/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.80*
RIM-YEC - Net Present Value	*-$4.91*
RIM-YEC - Levelized Cost	*$0.2706/kWh*

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$6.00
Assumed Program Administration Costs in Year 1	$11.32
Assumed Net-to-gross Ratio	55%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$32.31	$32.31
Discounted Cumulative Gross Energy Savings for 4 years	148 kWh	148 kWh
PC - Present Value of Benefits	$38.31	$38.31
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$38.31	$38.31
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-0.7 yr	-0.7 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test from YEC Perspective (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$17.77	$17.77
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
RIM - Present Value of Benefits	$19.18	$19.18
RIM - Present Value of Costs	$35.09	$23.77
RIM - Benefit/Cost Ratio	0.5	0.8
RIM - Net Present Value	-$15.92	-$4.59
RIM - Levelized Cost	$0 3953/kWh	$0.2677/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
TRC - Present Value of Benefits	$19.18	$19.18
TRC - Present Value of Costs	$11.32	$0.00
TRC - Benefit/Cost Ratio	1.69	*
TRC - Net Present Value	$7.85	$19.18
TRC - Levelized Cost	$0.1276/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test from YEC Perspective (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
PAC - Present Value of Benefits	$19.18	$19.18
PAC - Present Value of Costs	$17.32	$6.00
PAC - Benefit/Cost Ratio	1.1	3 2
PAC - Net Present Value	$1.85	$13.18
PAC - Levelized Cost	$0.1951/kWh	$0.0676/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM89

Inputs - Measure Considerations	
Measure Name:	Typical High-Performance New Building - 25% Better
Incentive Amount:	$1.50/ft2
Measure/Project Cost:	$2.00/ft2
Gross Consumption Savings:	6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	6 kWh/ft2/yr
Gross Demand Savings:	.001 kW/ft2
Gross Demand Savings w/ T&D losses:	.001 kW/ft2
Participant's Savings on Year 1:	$1.03/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost Per Unit:	250%
Suggested Program Cost ($ per Unit):	$1.64
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	7.36
PC - Net Present Value	$12.72
PC - Levelized Cost	$0.0304/kWh
Simple Payback w/ Incentive (yr)	0.5 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.08*
RIM - Levelized Cost	*$0.2427/kWh*
TRC - Benefit/Cost Ratio	3.78
TRC - Net Present Value	$12.24
TRC - Levelized Cost	$0.0645/kWh
PAC - Benefit/Cost Ratio	*4.16*
PAC - Net Present Value	*$12.64*
PAC - Levelized Cost	*$0.0586/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$5.53*
RIM-YECL - Levelized Cost	*$0.1829/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.58*
RIM-YEC - Net Present Value	*$6.12*
RIM-YEC - Levelized Cost	*$0.1432/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$2.00
Incentive Amount in Year 1	$1.50
Assumed Program Administration Costs in Year 1	$2.50
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$13.22	$13.22
Discounted Cumulative Gross Energy Savings for 20 years	66 kWh	66 kWh
PC - Present Value of Benefits	$14.72	$14.72
PC - Present Value of Costs	$2.00	$2.00
PC - Benefit/Cost Ratio	7.36	7.36
PC - Net Present Value	$12.72	$12.72
PC - Levelized Cost	$0.0304/kWh	$0.0304/kWh
Simple Payback with Incentive	0 5 yr	0.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12.56	$12.56
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
RIM - Present Value of Benefits	$16.64	$16.64
RIM - Present Value of Costs	$16.56	$14.06
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.08	$2.58
RIM - Levelized Cost	$0 2427/kWh	$0.2060/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
TRC - Present Value of Benefits	$16.64	$16.64
TRC - Present Value of Costs	$4.40	$1.90
TRC - Benefit/Cost Ratio	3.78	8.8
TRC - Net Present Value	$12.24	$14.74
TRC - Levelized Cost	$0.0645/kWh	$0.0278/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
PAC - Present Value of Benefits	$16.64	$16.64
PAC - Present Value of Costs	$4.00	$1.50
PAC - Benefit/Cost Ratio	4.2	11.1
PAC - Net Present Value	$12.64	$15.14
PAC - Levelized Cost	$0.0586/kWh	$0.0220/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM90

Inputs - Measure Considerations	
Measure Name:	Typical High-Performance New Building - 40% Better
Incentive Amount:	$4.00/ft2
Measure/Project Cost:	$6.00/ft2
Gross Consumption Savings:	9 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	10 kWh/ft2/yr
Gross Demand Savings:	.002 kW/ft2
Gross Demand Savings w/ T&D losses:	.002 kW/ft2
Participant's Savings on Year 1:	$1.64/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost Per Unit:	250%
Suggested Program Cost ($ per Unit):	$2.63
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.19
PC - Net Present Value	$19.15
PC - Levelized Cost	$0.0569/kWh
Simple Payback w/ Incentive (yr)	1.2 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.02*
RIM - Levelized Cost	*$0.2436/kWh*
TRC - Benefit/Cost Ratio	3.25
TRC - Net Present Value	$18.42
TRC - Levelized Cost	$0.0751/kWh
PAC - Benefit/Cost Ratio	*4.09*
PAC - Net Present Value	*$20.12*
PAC - Levelized Cost	*$0.0595/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$8.85*
RIM-YECL - Levelized Cost	*$0.1829/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.57*
RIM-YEC - Net Present Value	*$9.69*
RIM-YEC - Levelized Cost	*$0.1441/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$6.00
Incentive Amount in Year 1	$4.00
Assumed Program Administration Costs in Year 1	$2.50
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$21.15	$21.15
Discounted Cumulative Gross Energy Savings for 20 years	105 kWh	105 kWh
PC - Present Value of Benefits	$25.15	$25.15
PC - Present Value of Costs	$6.00	$6.00
PC - Benefit/Cost Ratio	4.19	4.19
PC - Net Present Value	$19.15	$19.15
PC - Levelized Cost	$0.0569/kWh	$0.0569/kWh
Simple Payback with Incentive	1 2 yr	1.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$20.09	$20.09
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
RIM - Present Value of Benefits	$26.62	$26.62
RIM - Present Value of Costs	$26.59	$24.09
RIM - Benefit/Cost Ratio	1.0	1.1
RIM - Net Present Value	$0.02	$2.52
RIM - Levelized Cost	$0 2436/kWh	$0.2207/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
TRC - Present Value of Benefits	$26.62	$26.62
TRC - Present Value of Costs	$8.20	$5.70
TRC - Benefit/Cost Ratio	3.25	4.7
TRC - Net Present Value	$18.42	$20.92
TRC - Levelized Cost	$0.0751/kWh	$0.0522/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
PAC - Present Value of Benefits	$26.62	$26.62
PAC - Present Value of Costs	$6.50	$4.00
PAC - Benefit/Cost Ratio	4.1	6.7
PAC - Net Present Value	$20.12	$22.62
PAC - Levelized Cost	$0.0595/kWh	$0.0366/kWh

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Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM892

Inputs - Measure Considerations

Measure Name:	Gov. Typical High-Performance New Building - 25% Better
Incentive Amount:	$0.90 /ft2
Measure/Project Cost:	$2.00 /ft2
Gross Consumption Savings:	6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	6 kWh/yr
Gross Demand Savings:	0.00 kW/ft2
Gross Demand Savings w/ T&D losses:	0.00 kW
Participant's Savings on Year 1:	$1.26
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	82%
Suggested Program Cost (% of Incentive):	82%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	8.56
PC - Net Present Value	$15.13
PC - Levelized Cost	$0.0304/kWh
Simple Payback w/ Incentive (yr)	0.9 yr
RIM - Benefit/Cost Ratio	*0.98*
RIM - Net Present Value	*-$0.41*
RIM - Levelized Cost	*$0.2498/kWh*
TRC - Benefit/Cost Ratio	6.32
TRC - Net Present Value	$14.00
TRC - Levelized Cost	$0.0386/kWh
PAC - Benefit/Cost Ratio	*10.18*
PAC - Net Present Value	*$15.00*
PAC - Levelized Cost	*$0.0239/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$8.17*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*2.21*
RIM-YEC - Net Present Value	*$9.88*
RIM-YEC - Levelized Cost	*$0.1111/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$2.00
Incentive Amount in Year 1	$0.90
Assumed Program Administration Costs in Year 1	$0.73
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16.23	$16.23
Discounted Cumulative Gross Energy Savings for 20 years	66 kWh	66 kWh
PC - Present Value of Benefits	$17.13	$17.13
PC - Present Value of Costs	$2.00	$2.00
PC - Benefit/Cost Ratio	8.56	8.56
PC - Net Present Value	$15.13	$15.13
PC - Levelized Cost	$0.0304/kWh	$0.0304/kWh
Simple Payback with Incentive	0 9 yr	0.9 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$15.41	$15.41
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
RIM - Present Value of Benefits	$16.64	$16.64
RIM - Present Value of Costs	$17.05	$16.31
RIM - Benefit/Cost Ratio	1.0	1.0
RIM - Net Present Value	-$0.41	$0.32
RIM - Levelized Cost	$0 2498/kWh	$0.2391/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
TRC - Present Value of Benefits	$16.64	$16.64
TRC - Present Value of Costs	$2.63	$1.90
TRC - Benefit/Cost Ratio	6.32	8.8
TRC - Net Present Value	$14.00	$14.74
TRC - Levelized Cost	$0.0386/kWh	$0.0278/kWh

Program Administrator Cost Test from YEC Perspective (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
PAC - Present Value of Benefits	$16.64	$16.64
PAC - Present Value of Costs	$1.63	$0.90
PAC - Benefit/Cost Ratio	10.2	18 5
PAC - Net Present Value	$15.00	$15.74
PAC - Levelized Cost	$0.0239/kWh	$0.0132/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM902

Inputs - Measure Considerations

Measure Name: Gov. Typical High-Performance New Building - 40% Better	
Incentive Amount:	$2.40 /ft2
Measure/Project Cost:	$6.00 /ft2
Gross Consumption Savings:	9 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	10 kWh/yr
Gross Demand Savings:	0.00 kW/ft2
Gross Demand Savings w/ T&D losses:	0.00 kW
Participant's Savings on Year 1:	$2.01
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	82%
Suggested Program Cost (% of Incentive):	82%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	4.73
PC - Net Present Value	$22.36
PC - Levelized Cost	$0.0569/kWh
Simple Payback w/ Incentive (yr)	1.8 yr
RIM - Benefit/Cost Ratio	*0.92*
RIM - Net Present Value	*-$2.40*
RIM - Levelized Cost	*$0.2658/kWh*
TRC - Benefit/Cost Ratio	3.48
TRC - Net Present Value	$18.96
TRC - Levelized Cost	$0.0701/kWh
PAC - Benefit/Cost Ratio	*6.11*
PAC - Net Present Value	*$22.26*
PAC - Levelized Cost	*$0.0399/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$13.07*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.95*
RIM-YEC - Net Present Value	*$14.07*
RIM-YEC - Levelized Cost	*$0.1259/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$6.00
Incentive Amount in Year 1	$2.40
Assumed Program Administration Costs in Year 1	$1.96
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$25.96	$25.96
Discounted Cumulative Gross Energy Savings for 20 years	105 kWh	105 kWh
PC - Present Value of Benefits	$28.36	$28.36
PC - Present Value of Costs	$6.00	$6.00
PC - Benefit/Cost Ratio	4.73	4.73
PC - Net Present Value	$22.36	$22.36
PC - Levelized Cost	$0.0569/kWh	$0.0569/kWh
Simple Payback with Incentive	1.8 yr	1.8 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$24.66	$24.66
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
RIM - Present Value of Benefits	$26.62	$26.62
RIM - Present Value of Costs	$29.02	$27.06
RIM - Benefit/Cost Ratio	0.9	1.0
RIM - Net Present Value	-$2.40	-$0.45
RIM - Levelized Cost	$0 2658/kWh	$0.2479/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
TRC - Present Value of Benefits	$26.62	$26.62
TRC - Present Value of Costs	$7.66	$5.70
TRC - Benefit/Cost Ratio	3.48	4.7
TRC - Net Present Value	$18.96	$20.92
TRC - Levelized Cost	$0.0701/kWh	$0.0522/kWh

Program Administrator Cost Test from YEC Perspective (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
PAC - Present Value of Benefits	$26.62	$26.62
PAC - Present Value of Costs	$4.36	$2.40
PAC - Benefit/Cost Ratio	6.1	11.1
PAC - Net Present Value	$22.26	$24.22
PAC - Levelized Cost	$0.0399/kWh	$0.0220/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM24

Inputs - Measure Considerations	
Measure Name:	12W LED A19 Bulb
Incentive Amount:	$18.00
Measure/Project Cost:	$44.00
Gross Consumption Savings:	48 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	52 kWh/yr
Gross Demand Savings:	.017 kW
Gross Demand Savings w/ T&D losses:	.019 kW
Participant's Savings on Year 1:	$6.97
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	177%
Suggested Program Cost (% of Incentive):	177%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.45
PC - Net Present Value	$63.93
PC - Levelized Cost	$0.0825/kWh
Simple Payback w/ Incentive (yr)	3.7 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$7.15*
RIM - Levelized Cost	*$0.2326/kWh*
TRC - Benefit/Cost Ratio	1.94
TRC - Net Present Value	$75.67
TRC - Levelized Cost	$0.1255/kWh
PAC - Benefit/Cost Ratio	*3.13*
PAC - Net Present Value	*$106.07*
PAC - Levelized Cost	*$0.0779/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$34.47*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.52*
RIM-YEC - Net Present Value	*$58.11*
RIM-YEC - Levelized Cost	*$0.1612/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$44.00
Incentive Amount in Year 1	$18.00
Assumed Program Administration Costs in Year 1	$31.84
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$89.93	$89.93
Discounted Cumulative Gross Energy Savings for 20 years	533 kWh	533 kWh
PC - Present Value of Benefits	$107.93	$107.93
PC - Present Value of Costs	$44.00	$44.00
PC - Benefit/Cost Ratio	2.45	2.45
PC - Net Present Value	$63.93	$63.93
PC - Levelized Cost	$0.0825/kWh	$0.0825/kWh
Simple Payback with Incentive	3.7 yr	3.7 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$98.92	$98.92
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
RIM - Present Value of Benefits	$155.92	$155.92
RIM - Present Value of Costs	$148.77	$116.92
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$7.15	$38.99
RIM - Levelized Cost	$0 2326/kWh	$0.1828/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
TRC - Present Value of Benefits	$155.92	$155.92
TRC - Present Value of Costs	$80.24	$48.40
TRC - Benefit/Cost Ratio	1.94	3 2
TRC - Net Present Value	$75.67	$107.52
TRC - Levelized Cost	$0.1255/kWh	$0.0757/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
PAC - Present Value of Benefits	$155.92	$155.92
PAC - Present Value of Costs	$49.84	$18.00
PAC - Benefit/Cost Ratio	3.1	8.7
PAC - Net Present Value	$106.07	$137.92
PAC - Levelized Cost	$0.0779/kWh	$0.0281/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM60

Inputs - Measure Considerations	
Measure Name:	8W LED A19 Bulb
Incentive Amount:	$12.00
Measure/Project Cost:	$30.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.65
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	177%
Suggested Program Cost (% of Incentive):	177%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.40
PC - Net Present Value	$41.95
PC - Levelized Cost	$0.0844/kWh
Simple Payback w/ Incentive (yr)	3.9 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$4.76*
RIM - Levelized Cost	*$0.2326/kWh*
TRC - Benefit/Cost Ratio	1.92
TRC - Net Present Value	$49.71
TRC - Levelized Cost	$0.1272/kWh
PAC - Benefit/Cost Ratio	*3.13*
PAC - Net Present Value	*$70.71*
PAC - Levelized Cost	*$0.0779/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$22.98*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.52*
RIM-YEC - Net Present Value	*$38.74*
RIM-YEC - Levelized Cost	*$0.1612/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$30.00
Incentive Amount in Year 1	$12.00
Assumed Program Administration Costs in Year 1	$21.23
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$59.95	$59.95
Discounted Cumulative Gross Energy Savings for 20 years	355 kWh	355 kWh
PC - Present Value of Benefits	$71.95	$71.95
PC - Present Value of Costs	$30.00	$30.00
PC - Benefit/Cost Ratio	2.40	2.40
PC - Net Present Value	$41.95	$41.95
PC - Levelized Cost	$0.0844/kWh	$0.0844/kWh
Simple Payback with Incentive	3 9 yr	3.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$65.95	$65.95
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
RIM - Present Value of Benefits	$103.94	$103.94
RIM - Present Value of Costs	$99.18	$77.95
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$4.76	$25.99
RIM - Levelized Cost	$0 2326/kWh	$0.1828/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
TRC - Present Value of Benefits	$103.94	$103.94
TRC - Present Value of Costs	$54.23	$33.00
TRC - Benefit/Cost Ratio	1.92	3.1
TRC - Net Present Value	$49.71	$70.94
TRC - Levelized Cost	$0.1272/kWh	$0.0774/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
PAC - Present Value of Benefits	$103.94	$103.94
PAC - Present Value of Costs	$33.23	$12.00
PAC - Benefit/Cost Ratio	3.1	8.7
PAC - Net Present Value	$70.71	$91.94
PAC - Levelized Cost	$0.0779/kWh	$0.0281/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations	
Measure Name:	LED MR16 Bulbs
Incentive Amount:	$10.00
Measure/Project Cost:	$20.00
Gross Consumption Savings:	15 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	16 kWh/yr
Gross Demand Savings:	.005 kW
Gross Demand Savings w/ T&D losses:	.006 kW
Participant's Savings on Year 1:	$2.18
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	100%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.91
PC - Net Present Value	$18.10
PC - Levelized Cost	$0.1200/kWh
Simple Payback w/ Incentive (yr)	4.6 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$2.14*
RIM - Levelized Cost	*$0.2545/kWh*
TRC - Benefit/Cost Ratio	1.52
TRC - Net Present Value	$16.77
TRC - Levelized Cost	$0.1599/kWh
PAC - Benefit/Cost Ratio	*2.44*
PAC - Net Present Value	*$28.77*
PAC - Levelized Cost	*$0.0998/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$10.77*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.35*
RIM-YEC - Net Present Value	*$13.79*
RIM-YEC - Levelized Cost	*$0.1814/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$20.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$9.95
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$28.10	$28.10
Discounted Cumulative Gross Energy Savings for 20 years	167 kWh	167 kWh
PC - Present Value of Benefits	$38.10	$38.10
PC - Present Value of Costs	$20.00	$20.00
PC - Benefit/Cost Ratio	1.91	1.91
PC - Net Present Value	$18.10	$18.10
PC - Levelized Cost	$0.1200/kWh	$0.1200/kWh
Simple Payback with Incentive	4.6 yr	4.6 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$30.91	$30.91
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
RIM - Present Value of Benefits	$48.72	$48.72
RIM - Present Value of Costs	$50.87	$40.91
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	-$2.14	$7.81
RIM - Levelized Cost	$0 2545/kWh	$0.2047/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
TRC - Present Value of Benefits	$48.72	$48.72
TRC - Present Value of Costs	$31.95	$22.00
TRC - Benefit/Cost Ratio	1.52	2 2
TRC - Net Present Value	$16.77	$26.72
TRC - Levelized Cost	$0.1599/kWh	$0.1101/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
PAC - Present Value of Benefits	$48.72	$48.72
PAC - Present Value of Costs	$19.95	$10.00
PAC - Benefit/Cost Ratio	2.4	4 9
PAC - Net Present Value	$28.77	$38.72
PAC - Levelized Cost	$0.0998/kWh	$0.0500/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM62

Inputs - Measure Considerations	
Measure Name:	LED PAR30 Bulbs
Incentive Amount:	$20.00
Measure/Project Cost:	$51.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	.016 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	133%
Suggested Program Cost (% of Incentive):	133%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.86
PC - Net Present Value	$43.94
PC - Levelized Cost	$0.1148/kWh
Simple Payback w/ Incentive (yr)	5.3 yr
RIM - Benefit/Cost Ratio	*1.01*
RIM - Net Present Value	*$0.95*
RIM - Levelized Cost	*$0.2420/kWh*
TRC - Benefit/Cost Ratio	1.57
TRC - Net Present Value	$47.29
TRC - Levelized Cost	$0.1551/kWh
PAC - Benefit/Cost Ratio	*2.79*
PAC - Net Present Value	*$83.39*
PAC - Levelized Cost	*$0.0873/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.72*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.44*
RIM-YEC - Net Present Value	*$43.43*
RIM-YEC - Levelized Cost	*$0.1698/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$51.00
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$26.54
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.94	$74.94
Discounted Cumulative Gross Energy Savings for 20 years	444 kWh	444 kWh
PC - Present Value of Benefits	$94.94	$94.94
PC - Present Value of Costs	$51.00	$51.00
PC - Benefit/Cost Ratio	1.86	1.86
PC - Net Present Value	$43.94	$43.94
PC - Levelized Cost	$0.1148/kWh	$0.1148/kWh
Simple Payback with Incentive	5 3 yr	5.3 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$82.44	$82.44
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
RIM - Present Value of Benefits	$129.93	$129.93
RIM - Present Value of Costs	$128.97	$102.44
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$0.95	$27.49
RIM - Levelized Cost	$0 2420/kWh	$0.1922/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
TRC - Present Value of Benefits	$129.93	$129.93
TRC - Present Value of Costs	$82.64	$56.10
TRC - Benefit/Cost Ratio	1.57	2 3
TRC - Net Present Value	$47.29	$73.83
TRC - Levelized Cost	$0.1551/kWh	$0.1053/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
PAC - Present Value of Benefits	$129.93	$129.93
PAC - Present Value of Costs	$46.54	$20.00
PAC - Benefit/Cost Ratio	2.8	6 5
PAC - Net Present Value	$83.39	$109.93
PAC - Levelized Cost	$0.0873/kWh	$0.0375/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM63

Inputs - Measure Considerations	
Measure Name:	LED PAR38 Bulbs
Incentive Amount:	$20.00
Measure/Project Cost:	$43.00
Gross Consumption Savings:	55 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	60 kWh/yr
Gross Demand Savings:	.02 kW
Gross Demand Savings w/ T&D losses:	.021 kW
Participant's Savings on Year 1:	$7.99
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	182%
Suggested Program Cost (% of Incentive):	182%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.86
PC - Net Present Value	$80.05
PC - Levelized Cost	$0.0704/kWh
Simple Payback w/ Incentive (yr)	2.9 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$8.81*
RIM - Levelized Cost	*$0.2318/kWh*
TRC - Benefit/Cost Ratio	2.13
TRC - Net Present Value	$94.86
TRC - Levelized Cost	$0.1143/kWh
PAC - Benefit/Cost Ratio	*3.16*
PAC - Net Present Value	*$122.16*
PAC - Levelized Cost	*$0.0771/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$39.49*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.53*
RIM-YEC - Net Present Value	*$67.21*
RIM-YEC - Levelized Cost	*$0.1604/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$43.00
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$36.49
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$103.05	$103.05
Discounted Cumulative Gross Energy Savings for 20 years	611 kWh	611 kWh
PC - Present Value of Benefits	$123.05	$123.05
PC - Present Value of Costs	$43.00	$43.00
PC - Benefit/Cost Ratio	2.86	2.86
PC - Net Present Value	$80.05	$80.05
PC - Levelized Cost	$0.0704/kWh	$0.0704/kWh
Simple Payback with Incentive	2 9 yr	2.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$113.35	$113.35
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
RIM - Present Value of Benefits	$178.65	$178.65
RIM - Present Value of Costs	$169.84	$133.35
RIM - Benefit/Cost Ratio	1.1	1 3
RIM - Net Present Value	$8.81	$45.30
RIM - Levelized Cost	$0 2318/kWh	$0.1820/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
TRC - Present Value of Benefits	$178.65	$178.65
TRC - Present Value of Costs	$83.79	$47.30
TRC - Benefit/Cost Ratio	2.13	3.8
TRC - Net Present Value	$94.86	$131.35
TRC - Levelized Cost	$0.1143/kWh	$0.0645/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
PAC - Present Value of Benefits	$178.65	$178.65
PAC - Present Value of Costs	$56.49	$20.00
PAC - Benefit/Cost Ratio	3.2	8 9
PAC - Net Present Value	$122.16	$158.65
PAC - Levelized Cost	$0.0771/kWh	$0.0273/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM44

Inputs - Measure Considerations	
Measure Name:	Spot or Task Lighting
Incentive Amount:	$10.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	.016 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	96%
Suggested Program Cost (% of Incentive):	96%
Forecasted Freeridership:	20%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.27
PC - Net Present Value	$31.76
PC - Levelized Cost	$0.0841/kWh
Simple Payback w/ Incentive (yr)	2.6 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$1.90*
RIM - Levelized Cost	*$0.2200/kWh*
TRC - Benefit/Cost Ratio	1.99
TRC - Net Present Value	$29.31
TRC - Levelized Cost	$0.1143/kWh
PAC - Benefit/Cost Ratio	*3.00*
PAC - Net Present Value	*$39.31*
PAC - Levelized Cost	*$0.0758/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$13.53*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$19.58*
RIM-YEC - Levelized Cost	*$0.1553/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$9.65
Assumed Net-to-gross Ratio	80%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$46.76	$46.76
Discounted Cumulative Gross Energy Savings for 10 years	297 kWh	297 kWh
PC - Present Value of Benefits	$56.76	$56.76
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.27	2.27
PC - Net Present Value	$31.76	$31.76
PC - Levelized Cost	$0.0841/kWh	$0.0841/kWh
Simple Payback with Incentive	2.6 yr	2.6 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$37.41	$37.41
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
RIM - Present Value of Benefits	$58.96	$58.96
RIM - Present Value of Costs	$57.06	$47.41
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$1.90	$11.55
RIM - Levelized Cost	$0 2200/kWh	$0.1828/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
TRC - Present Value of Benefits	$58.96	$58.96
TRC - Present Value of Costs	$29.65	$20.00
TRC - Benefit/Cost Ratio	1.99	2 9
TRC - Net Present Value	$29.31	$38.96
TRC - Levelized Cost	$0.1143/kWh	$0.0771/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
PAC - Present Value of Benefits	$58.96	$58.96
PAC - Present Value of Costs	$19.65	$10.00
PAC - Benefit/Cost Ratio	3.0	5 9
PAC - Net Present Value	$39.31	$48.96
PAC - Levelized Cost	$0.0758/kWh	$0.0386/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM151

Inputs - Measure Considerations	
Measure Name:	Block Heater Timer
Incentive Amount:	$20.00
Measure/Project Cost:	$37.50
Gross Consumption Savings:	130 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	142 kWh/yr
Gross Demand Savings:	0.05 kW
Gross Demand Savings w/ T&D losses:	0.05 kW
Participant's Savings on Year 1:	$18.86
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	378%
Suggested Program Cost (% of Incentive):	378%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.58
PC - Net Present Value	$134.24
PC - Levelized Cost	$0.0389/kWh
Simple Payback w/ Incentive (yr)	0.9 yr
RIM - Benefit/Cost Ratio	*0.97*
RIM - Net Present Value	*-$8.20*
RIM - Levelized Cost	*$0.2351/kWh*
TRC - Benefit/Cost Ratio	2.11
TRC - Net Present Value	$126.05
TRC - Levelized Cost	$0.1075/kWh
PAC - Benefit/Cost Ratio	*2.50*
PAC - Net Present Value	*$143.55*
PAC - Levelized Cost	*$0.0909/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$54.89*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.34*
RIM-YEC - Net Present Value	*$63.49*
RIM-YEC - Levelized Cost	*$0.1698/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.50
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$75.62
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$151.74	$151.74
Discounted Cumulative Gross Energy Savings for 10 years	965 kWh	965 kWh
PC - Present Value of Benefits	$171.74	$171.74
PC - Present Value of Costs	$37.50	$37.50
PC - Benefit/Cost Ratio	4.58	4.58
PC - Net Present Value	$134.24	$134.24
PC - Levelized Cost	$0.0389/kWh	$0.0389/kWh
Simple Payback with Incentive	0 9 yr	0.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$151.74	$151.74
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
RIM - Present Value of Benefits	$239.16	$239.16
RIM - Present Value of Costs	$247.36	$171.74
RIM - Benefit/Cost Ratio	1.0	1.4
RIM - Net Present Value	-$8.20	$67.42
RIM - Levelized Cost	$0 2351/kWh	$0.1632/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
TRC - Present Value of Benefits	$239.16	$239.16
TRC - Present Value of Costs	$113.12	$37.50
TRC - Benefit/Cost Ratio	2.11	6.4
TRC - Net Present Value	$126.05	$201.66
TRC - Levelized Cost	$0.1075/kWh	$0.0356/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
PAC - Present Value of Benefits	$239.16	$239.16
PAC - Present Value of Costs	$95.62	$20.00
PAC - Benefit/Cost Ratio	2.5	12.0
PAC - Net Present Value	$143.55	$219.16
PAC - Levelized Cost	$0.0909/kWh	$0.0190/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM091

Inputs - Measure Considerations	
Measure Name:	Ed. Ultra Low-flow Showerheads
Incentive Amount:	$0.00
Measure/Project Cost:	$8.62
Gross Consumption Savings:	325 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	354 kWh/yr
Gross Demand Savings:	.116 kW
Gross Demand Savings w/ T&D losses:	.126 kW
Participant's Savings on Year 1:	$47.22
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit	$193.78
Suggested Program Cost ($ per Unit):	$193.78
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	44.08
PC - Net Present Value	$371.34
PC - Levelized Cost	$0.0036/kWh
Simple Payback w/ Incentive (yr)	0.2 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$25.12*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	2.96
TRC - Net Present Value	$396.46
TRC - Levelized Cost	$0.0768/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$405.08*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$137.43*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$204.61*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8.62
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$193.78
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$379.96	$379.96
Discounted Cumulative Gross Energy Savings for 10 years	2,416 kWh	2,416 kWh
PC - Present Value of Benefits	$379.96	$379.96
PC - Present Value of Costs	$8.62	$8.62
PC - Benefit/Cost Ratio	44.08	44.08
PC - Net Present Value	$371.34	$371.34
PC - Levelized Cost	$0.0036/kWh	$0.0036/kWh
Simple Payback with Incentive	0 2 yr	0.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$379.96	$379.96
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
RIM - Present Value of Benefits	$598.86	$598.86
RIM - Present Value of Costs	$573.74	$379.96
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$25.12	$218.90
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
TRC - Present Value of Benefits	$598.86	$598.86
TRC - Present Value of Costs	$202.40	$8.62
TRC - Benefit/Cost Ratio	2.96	69 5
TRC - Net Present Value	$396.46	$590.24
TRC - Levelized Cost	$0.0768/kWh	$0.0033/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
PAC - Present Value of Benefits	$598.86	$598.86
PAC - Present Value of Costs	$193.78	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$405.08	$598.86
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM111

Inputs - Measure Considerations	
Measure Name:	Ed. Smart, Surge Protected Power Bars for PCs and TVs
Incentive Amount:	$0.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	68 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	74 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.85
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit	$40.41
Suggested Program Cost ($ per Unit):	$40.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.17
PC - Net Present Value	$54.24
PC - Levelized Cost	$0.0496/kWh
Simple Payback w/ Incentive (yr)	2.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.24*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	1.91
TRC - Net Present Value	$59.48
TRC - Levelized Cost	$0.1191/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$84.48*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.66*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$42.67*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$40.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$79.24	$79.24
Discounted Cumulative Gross Energy Savings for 10 years	504 kWh	504 kWh
PC - Present Value of Benefits	$79.24	$79.24
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	3.17	3.17
PC - Net Present Value	$54.24	$54.24
PC - Levelized Cost	$0.0496/kWh	$0.0496/kWh
Simple Payback with Incentive	2 5 yr	2.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$79.24	$79.24
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
RIM - Present Value of Benefits	$124.89	$124.89
RIM - Present Value of Costs	$119.66	$79.24
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.24	$45.65
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
TRC - Present Value of Benefits	$124.89	$124.89
TRC - Present Value of Costs	$65.41	$25.00
TRC - Benefit/Cost Ratio	1.91	5.0
TRC - Net Present Value	$59.48	$99.89
TRC - Levelized Cost	$0.1191/kWh	$0.0455/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
PAC - Present Value of Benefits	$124.89	$124.89
PAC - Present Value of Costs	$40.41	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$84.48	$124.89
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM181

Inputs - Measure Considerations	
Measure Name:	Ed. DHW Tank Insulation
Incentive Amount:	$0.00
Measure/Project Cost:	$37.58
Gross Consumption Savings:	62 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	68 kWh/yr
Gross Demand Savings:	.022 kW
Gross Demand Savings w/ T&D losses:	.024 kW
Participant's Savings on Year 1:	$9.01
Measure Lifetime:	14 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$51.75
Suggested Program Cost ($ per Unit):	$51.75
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.47
PC - Net Present Value	$55.06
PC - Levelized Cost	$0.0658/kWh
Simple Payback w/ Incentive (yr)	4.2 yr
RIM - Benefit/Cost Ratio	*1.01*
RIM - Net Present Value	*$1.62*
RIM - Levelized Cost	*$0.2317/kWh*
TRC - Benefit/Cost Ratio	1.63
TRC - Net Present Value	$56.68
TRC - Levelized Cost	$0.1433/kWh
PAC - Benefit/Cost Ratio	*2.82*
PAC - Net Present Value	*$94.26*
PAC - Levelized Cost	*$0.0830/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$32.97*
RIM-YECL - Levelized Cost	*$0.1482/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.44*
RIM-YEC - Net Present Value	*$47.04*
RIM-YEC - Levelized Cost	*$0.1637/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.58
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$51.75
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 14 years	$92.64	$92.64
Discounted Cumulative Gross Energy Savings for 14 years	571 kWh	571 kWh
PC - Present Value of Benefits	$92.64	$92.64
PC - Present Value of Costs	$37.58	$37.58
PC - Benefit/Cost Ratio	2.47	2.47
PC - Net Present Value	$55.06	$55.06
PC - Levelized Cost	$0.0658/kWh	$0.0658/kWh
Simple Payback with Incentive	4 2 yr	4.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Present Value of Lost Revenues for 14 years	$92.64	$92.64
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
RIM - Present Value of Benefits	$146.01	$146.01
RIM - Present Value of Costs	$144.40	$92.64
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$1.62	$53.37
RIM - Levelized Cost	$0 2317/kWh	$0.1487/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
TRC - Present Value of Benefits	$146.01	$146.01
TRC - Present Value of Costs	$89.33	$37.58
TRC - Benefit/Cost Ratio	1.63	3 9
TRC - Net Present Value	$56.68	$108.43
TRC - Levelized Cost	$0.1433/kWh	$0.0603/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
PAC - Present Value of Benefits	$146.01	$146.01
PAC - Present Value of Costs	$51.75	$0.00
PAC - Benefit/Cost Ratio	2.8	#DIV/0!
PAC - Net Present Value	$94.26	$146.01
PAC - Levelized Cost	$0.0830/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM201

Inputs - Measure Considerations	
Measure Name:	Ed. DHW Pipe Insulation
Incentive Amount:	$0.00
Measure/Project Cost:	$0.79
Gross Consumption Savings:	34 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	37 kWh/yr
Gross Demand Savings:	.012 kW
Gross Demand Savings w/ T&D losses:	.013 kW
Participant's Savings on Year 1:	$4.94
Measure Lifetime:	15 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$30.41
Suggested Program Cost ($ per Unit):	$30.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	67.39
PC - Net Present Value	$52.44
PC - Levelized Cost	$0.0024/kWh
Simple Payback w/ Incentive (yr)	0.2 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.26*
RIM - Levelized Cost	*$0.2352/kWh*
TRC - Benefit/Cost Ratio	2.69
TRC - Net Present Value	$52.70
TRC - Levelized Cost	$0.0877/kWh
PAC - Benefit/Cost Ratio	*2.76*
PAC - Net Present Value	*$53.49*
PAC - Levelized Cost	*$0.0855/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$18.88*
RIM-YECL - Levelized Cost	*$0.1492/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.42*
RIM-YEC - Net Present Value	*$26.59*
RIM-YEC - Levelized Cost	*$0.1664/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.79
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$30.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 15 years	$53.23	$53.23
Discounted Cumulative Gross Energy Savings for 15 years	326 kWh	326 kWh
PC - Present Value of Benefits	$53.23	$53.23
PC - Present Value of Costs	$0.79	$0.79
PC - Benefit/Cost Ratio	67.39	67.39
PC - Net Present Value	$52.44	$52.44
PC - Levelized Cost	$0.0024/kWh	$0.0024/kWh
Simple Payback with Incentive	0 2 yr	0.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Present Value of Lost Revenues for 15 years	$53.23	$53.23
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
RIM - Present Value of Benefits	$83.90	$83.90
RIM - Present Value of Costs	$83.64	$53.23
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$0.26	$30.67
RIM - Levelized Cost	$0 2352/kWh	$0.1497/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
TRC - Present Value of Benefits	$83.90	$83.90
TRC - Present Value of Costs	$31.20	$0.79
TRC - Benefit/Cost Ratio	2.69	106 2
TRC - Net Present Value	$52.70	$83.11
TRC - Levelized Cost	$0.0877/kWh	$0.0022/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
PAC - Present Value of Benefits	$83.90	$83.90
PAC - Present Value of Costs	$30.41	$0.00
PAC - Benefit/Cost Ratio	2.8	#DIV/0!
PAC - Net Present Value	$53.49	$83.90
PAC - Levelized Cost	$0.0855/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM481

Inputs - Measure Considerations	
Measure Name:	Ed. Motion Detectors - Indoor and Outdoor
Incentive Amount:	$0.00
Measure/Project Cost:	$22.94
Gross Consumption Savings:	66 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	72 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.59
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$39.35
Suggested Program Cost ($ per Unit):	$39.35
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.36
PC - Net Present Value	$54.21
PC - Levelized Cost	$0.0468/kWh
Simple Payback w/ Incentive (yr)	2.4 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.10*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	1.95
TRC - Net Present Value	$59.31
TRC - Levelized Cost	$0.1164/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$82.25*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$27.90*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$41.55*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$22.94
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$39.35
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$77.15	$77.15
Discounted Cumulative Gross Energy Savings for 10 years	490 kWh	490 kWh
PC - Present Value of Benefits	$77.15	$77.15
PC - Present Value of Costs	$22.94	$22.94
PC - Benefit/Cost Ratio	3.36	3.36
PC - Net Present Value	$54.21	$54.21
PC - Levelized Cost	$0.0468/kWh	$0.0468/kWh
Simple Payback with Incentive	2.4 yr	2.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$77.15	$77.15
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
RIM - Present Value of Benefits	$121.60	$121.60
RIM - Present Value of Costs	$116.50	$77.15
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.10	$44.45
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
TRC - Present Value of Benefits	$121.60	$121.60
TRC - Present Value of Costs	$62.28	$22.94
TRC - Benefit/Cost Ratio	1.95	5 3
TRC - Net Present Value	$59.31	$98.66
TRC - Levelized Cost	$0.1164/kWh	$0.0429/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
PAC - Present Value of Benefits	$121.60	$121.60
PAC - Present Value of Costs	$39.35	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$82.25	$121.60
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM141

Inputs - Measure Considerations	
Measure Name:	Ed. Prog. Thermostats (Central)
Incentive Amount:	$0.00
Measure/Project Cost:	$62.50
Gross Consumption Savings:	827 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	902 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.322 kW
Participant's Savings on Year 1:	$120.16
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$542.41
Suggested Program Cost ($ per Unit):	$542.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	16.63
PC - Net Present Value	$976.76
PC - Levelized Cost	$0.0095/kWh
Simple Payback w/ Incentive (yr)	0.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$56.31*
RIM - Levelized Cost	*$0.2212/kWh*
TRC - Benefit/Cost Ratio	2.71
TRC - Net Present Value	$1,033.07
TRC - Levelized Cost	$0.0846/kWh
PAC - Benefit/Cost Ratio	*3.02*
PAC - Net Present Value	*$1,095.57*
PAC - Levelized Cost	*$0.0759/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$374.34*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$552.01*
RIM-YEC - Levelized Cost	*$0.1557/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$62.50
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$542.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,039 26	$1,039.26
Discounted Cumulative Gross Energy Savings for 11 years	6,556 kWh	6,556 kWh
PC - Present Value of Benefits	$1,039.26	$1,039.26
PC - Present Value of Costs	$62.50	$62.50
PC - Benefit/Cost Ratio	16.63	16.63
PC - Net Present Value	$976.76	$976.76
PC - Levelized Cost	$0.0095/kWh	$0.0095/kWh
Simple Payback with Incentive	0 5 yr	0.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,039.26	$1,039.26
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
RIM - Present Value of Benefits	$1,637.98	$1,637.98
RIM - Present Value of Costs	$1,581.66	$1,039.26
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$56.31	$598.72
RIM - Levelized Cost	$0 2212/kWh	$0.1454/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
TRC - Present Value of Benefits	$1,637.98	$1,637.98
TRC - Present Value of Costs	$604.91	$62.50
TRC - Benefit/Cost Ratio	2.71	26 2
TRC - Net Present Value	$1,033.07	$1,575.48
TRC - Levelized Cost	$0.0846/kWh	$0.0087/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
PAC - Present Value of Benefits	$1,637.98	$1,637.98
PAC - Present Value of Costs	$542.41	$0.00
PAC - Benefit/Cost Ratio	3.0	#DIV/0!
PAC - Net Present Value	$1,095.57	$1,637.98
PAC - Levelized Cost	$0.0759/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM211

Inputs - Measure Considerations	
Measure Name:	Ed. Prog. Thermostats
Incentive Amount:	$0.00
Measure/Project Cost:	$285.43
Gross Consumption Savings:	826 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	901 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.321 kW
Participant's Savings on Year 1:	$120.02
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$541.75
Suggested Program Cost ($ per Unit):	$541.75
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.64
PC - Net Present Value	$752.57
PC - Levelized Cost	$0.0436/kWh
Simple Payback w/ Incentive (yr)	2.4 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$56.25*
RIM - Levelized Cost	*$0.2212/kWh*
TRC - Benefit/Cost Ratio	1.98
TRC - Net Present Value	$808.82
TRC - Levelized Cost	$0.1158/kWh
PAC - Benefit/Cost Ratio	*3.02*
PAC - Net Present Value	*$1,094.25*
PAC - Levelized Cost	*$0.0759/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$373.89*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$551.34*
RIM-YEC - Levelized Cost	*$0.1557/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$285.43
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$541.75
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Gross Energy Savings for 11 years	6,548 kWh	6,548 kWh
PC - Present Value of Benefits	$1,038.00	$1,038.00
PC - Present Value of Costs	$285.43	$285.43
PC - Benefit/Cost Ratio	3.64	3.64
PC - Net Present Value	$752.57	$752.57
PC - Levelized Cost	$0.0436/kWh	$0.0436/kWh
Simple Payback with Incentive	2.4 yr	2.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
RIM - Present Value of Benefits	$1,636.00	$1,636.00
RIM - Present Value of Costs	$1,579.75	$1,038.00
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$56.25	$598.00
RIM - Levelized Cost	$0 2212/kWh	$0.1454/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
TRC - Present Value of Benefits	$1,636.00	$1,636.00
TRC - Present Value of Costs	$827.18	$285.43
TRC - Benefit/Cost Ratio	1.98	5.7
TRC - Net Present Value	$808.82	$1,350.57
TRC - Levelized Cost	$0.1158/kWh	$0.0400/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
PAC - Present Value of Benefits	$1,636.00	$1,636.00
PAC - Present Value of Costs	$541.75	$0.00
PAC - Benefit/Cost Ratio	3.0	#DIV/0!
PAC - Net Present Value	$1,094.25	$1,636.00
PAC - Levelized Cost	$0.0759/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM061

Inputs - Measure Considerations	
Measure Name:	Ed. E-Star TVs
Incentive Amount:	$0.00
Measure/Project Cost:	$125.00
Gross Consumption Savings:	69 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	75 kWh/yr
Gross Demand Savings:	.025 kW
Gross Demand Savings w/ T&D losses:	.027 kW
Participant's Savings on Year 1:	$10.03
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$41.14
Suggested Program Cost ($ per Unit):	$41.14
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.65
PC - Net Present Value	-$44.33
PC - Levelized Cost	$0.2437/kWh
Simple Payback w/ Incentive (yr)	12.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.33*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	0.77
TRC - Net Present Value	-$39.00
TRC - Levelized Cost	$0.2971/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$86.00*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$29.18*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$43.44*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$125.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$41.14
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$80.67	$80.67
Discounted Cumulative Gross Energy Savings for 10 years	513 kWh	513 kWh
PC - Present Value of Benefits	$80.67	$80.67
PC - Present Value of Costs	$125.00	$125.00
PC - Benefit/Cost Ratio	0.65	0.65
PC - Net Present Value	-$44.33	-$44.33
PC - Levelized Cost	$0 2437/kWh	$0.2437/kWh
Simple Payback with Incentive	12 5 yr	12.5 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$80.67	$80.67
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
RIM - Present Value of Benefits	$127.14	$127.14
RIM - Present Value of Costs	$121.81	$80.67
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.33	$46.47
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
TRC - Present Value of Benefits	$127.14	$127.14
TRC - Present Value of Costs	$166.14	$125.00
TRC - Benefit/Cost Ratio	0.77	1.0
TRC - Net Present Value	-$39.00	$2.14
TRC - Levelized Cost	$0 2971/kWh	$0.2235/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
PAC - Present Value of Benefits	$127.14	$127.14
PAC - Present Value of Costs	$41.14	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$86.00	$127.14
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM081

Inputs - Measure Considerations	
Measure Name:	Ed. ESTAR Printers and Fax
Incentive Amount:	$0.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.61
Measure Lifetime:	6 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$11.36
Suggested Program Cost ($ per Unit):	$11.36
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.98
PC - Net Present Value	-$0.52
PC - Levelized Cost	$0.1554/kWh
Simple Payback w/ Incentive (yr)	5.4 yr
RIM - Benefit/Cost Ratio	*1.08*
RIM - Net Present Value	*$2.74*
RIM - Levelized Cost	*$0.2043/kWh*
TRC - Benefit/Cost Ratio	1.06
TRC - Net Present Value	$2.22
TRC - Levelized Cost	$0.2072/kWh
PAC - Benefit/Cost Ratio	*3.40*
PAC - Net Present Value	*$27.22*
PAC - Levelized Cost	*$0.0647/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.01*
RIM-YECL - Levelized Cost	*$0.1394/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.54*
RIM-YEC - Net Present Value	*$13.85*
RIM-YEC - Levelized Cost	*$0.1430/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$11.36
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 6 years	$24.48	$24.48
Discounted Cumulative Gross Energy Savings for 6 years	161 kWh	161 kWh
PC - Present Value of Benefits	$24.48	$24.48
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	0.98	0.98
PC - Net Present Value	-$0.52	-$0.52
PC - Levelized Cost	$0.1554/kWh	$0.1554/kWh
Simple Payback with Incentive	5.4 yr	5.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Present Value of Lost Revenues for 6 years	$24.48	$24.48
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
RIM - Present Value of Benefits	$38.58	$38.58
RIM - Present Value of Costs	$35.84	$24.48
RIM - Benefit/Cost Ratio	1.1	1.6
RIM - Net Present Value	$2.74	$14.10
RIM - Levelized Cost	$0 2043/kWh	$0.1395/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
TRC - Present Value of Benefits	$38.58	$38.58
TRC - Present Value of Costs	$36.36	$25.00
TRC - Benefit/Cost Ratio	1.06	1 5
TRC - Net Present Value	$2.22	$13.58
TRC - Levelized Cost	$0 2072/kWh	$0.1425/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
PAC - Present Value of Benefits	$38.58	$38.58
PAC - Present Value of Costs	$11.36	$0.00
PAC - Benefit/Cost Ratio	3.4	#DIV/0!
PAC - Net Present Value	$27.22	$38.58
PAC - Levelized Cost	$0.0647/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM242

Inputs - Measure Considerations	
Measure Name:	Pilot 12W LED A19 Bulb
Incentive Amount:	$44.00
Measure/Project Cost:	$44.00
Gross Consumption Savings:	48 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	52 kWh/yr
Gross Demand Savings:	.017 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$6.97
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	111%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.04
PC - Net Present Value	$89.93
PC - Levelized Cost	$0.0825/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.80*
RIM - Net Present Value	*-$36.19*
RIM - Levelized Cost	*$0.3060/kWh*
TRC - Benefit/Cost Ratio	1.61
TRC - Net Present Value	$53.74
TRC - Levelized Cost	$0.1514/kWh
PAC - Benefit/Cost Ratio	*1.61*
PAC - Net Present Value	*$53.74*
PAC - Levelized Cost	*$0.1514/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$31.33*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.07*
RIM-YEC - Net Present Value	*$10.14*
RIM-YEC - Levelized Cost	*$0.2292/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$44.00
Incentive Amount in Year 1	$44.00
Assumed Program Administration Costs in Year 1	$44.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$89.93	$89.93
Discounted Cumulative Gross Energy Savings for 20 years	533 kWh	533 kWh
PC - Present Value of Benefits	$133.93	$133.93
PC - Present Value of Costs	$44.00	$44.00
PC - Benefit/Cost Ratio	3.04	3.04
PC - Net Present Value	$89.93	$89.93
PC - Levelized Cost	$0.0825/kWh	$0.0825/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$89.93	$89.93
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
RIM - Present Value of Benefits	$141.74	$141.74
RIM - Present Value of Costs	$177.93	$133.93
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$36.19	$7.81
RIM - Levelized Cost	$0 3060/kWh	$0.2304/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
TRC - Present Value of Benefits	$141.74	$141.74
TRC - Present Value of Costs	$88.00	$44.00
TRC - Benefit/Cost Ratio	1.61	3 2
TRC - Net Present Value	$53.74	$97.74
TRC - Levelized Cost	$0.1514/kWh	$0.0757/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
PAC - Present Value of Benefits	$141.74	$141.74
PAC - Present Value of Costs	$88.00	$44.00
PAC - Benefit/Cost Ratio	1.6	3 2
PAC - Net Present Value	$53.74	$97.74
PAC - Levelized Cost	$0.1514/kWh	$0.0757/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM602

Inputs - Measure Considerations	
Measure Name:	Pilot 8W LED A19 Bulb
Incentive Amount:	$31.00
Measure/Project Cost:	$31.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$4.65
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	105%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.93
PC - Net Present Value	$59.95
PC - Levelized Cost	$0.0872/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.77*
RIM - Net Present Value	*-$27.46*
RIM - Levelized Cost	*$0.3146/kWh*
TRC - Benefit/Cost Ratio	1.52
TRC - Net Present Value	$32.49
TRC - Levelized Cost	$0.1600/kWh
PAC - Benefit/Cost Ratio	*1.52*
PAC - Net Present Value	*$32.49*
PAC - Levelized Cost	*$0.1600/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$20.89*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.03*
RIM-YEC - Net Present Value	*$3.43*
RIM-YEC - Levelized Cost	*$0.2372/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$31.00
Incentive Amount in Year 1	$31.00
Assumed Program Administration Costs in Year 1	$31.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$59.95	$59.95
Discounted Cumulative Gross Energy Savings for 20 years	355 kWh	355 kWh
PC - Present Value of Benefits	$90.95	$90.95
PC - Present Value of Costs	$31.00	$31.00
PC - Benefit/Cost Ratio	2.93	2.93
PC - Net Present Value	$59.95	$59.95
PC - Levelized Cost	$0.0872/kWh	$0.0872/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$59.95	$59.95
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
RIM - Present Value of Benefits	$94.49	$94.49
RIM - Present Value of Costs	$121.95	$90.95
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$27.46	$3.54
RIM - Levelized Cost	$0 3146/kWh	$0.2347/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
TRC - Present Value of Benefits	$94.49	$94.49
TRC - Present Value of Costs	$62.00	$31.00
TRC - Benefit/Cost Ratio	1.52	3.0
TRC - Net Present Value	$32.49	$63.49
TRC - Levelized Cost	$0.1600/kWh	$0.0800/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
PAC - Present Value of Benefits	$94.49	$94.49
PAC - Present Value of Costs	$62.00	$31.00
PAC - Benefit/Cost Ratio	1.5	3.0
PAC - Net Present Value	$32.49	$63.49
PAC - Levelized Cost	$0.1600/kWh	$0.0800/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM612

Inputs - Measure Considerations	
Measure Name:	Pilot LED MR16 Bulbs
Incentive Amount:	$25.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	15 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	16 kWh/yr
Gross Demand Savings:	.005 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$2.18
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	61%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.12
PC - Net Present Value	$28.10
PC - Levelized Cost	$0.1501/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.57*
RIM - Net Present Value	*-$33.81*
RIM - Levelized Cost	*$0.4299/kWh*
TRC - Benefit/Cost Ratio	0.89
TRC - Net Present Value	-$5.71
TRC - Levelized Cost	$0.2752/kWh
PAC - Benefit/Cost Ratio	*0.89*
PAC - Net Present Value	*-$5.71*
PAC - Levelized Cost	*$0.2752/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.79*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.71*
RIM-YEC - Net Present Value	*-$19.33*
RIM-YEC - Levelized Cost	*$0.3440/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$25.00
Assumed Program Administration Costs in Year 1	$25.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$28.10	$28.10
Discounted Cumulative Gross Energy Savings for 20 years	167 kWh	167 kWh
PC - Present Value of Benefits	$53.10	$53.10
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.12	2.12
PC - Net Present Value	$28.10	$28.10
PC - Levelized Cost	$0.1501/kWh	$0.1501/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$28.10	$28.10
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
RIM - Present Value of Benefits	$44.29	$44.29
RIM - Present Value of Costs	$78.10	$53.10
RIM - Benefit/Cost Ratio	0.6	0.8
RIM - Net Present Value	-$33.81	-$8.81
RIM - Levelized Cost	$0.4299/kWh	$0.2923/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
TRC - Present Value of Benefits	$44.29	$44.29
TRC - Present Value of Costs	$50.00	$25.00
TRC - Benefit/Cost Ratio	0.89	1.8
TRC - Net Present Value	-$5.71	$19.29
TRC - Levelized Cost	$0 2752/kWh	$0.1376/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
PAC - Present Value of Benefits	$44.29	$44.29
PAC - Present Value of Costs	$50.00	$25.00
PAC - Benefit/Cost Ratio	0.9	1.8
PAC - Net Present Value	-$5.71	$19.29
PAC - Levelized Cost	$0 2752/kWh	$0.1376/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM622

Inputs - Measure Considerations	
Measure Name:	Pilot LED PAR30 Bulbs
Incentive Amount:	$64.00
Measure/Project Cost:	$64.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	64%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.17
PC - Net Present Value	$74.94
PC - Levelized Cost	$0.1441/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.58*
RIM - Net Present Value	*-$84.83*
RIM - Levelized Cost	*$0.4189/kWh*
TRC - Benefit/Cost Ratio	0.92
TRC - Net Present Value	-$9.88
TRC - Levelized Cost	$0.2642/kWh
PAC - Benefit/Cost Ratio	*0.92*
PAC - Net Present Value	*-$9.88*
PAC - Levelized Cost	*$0.2642/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$26.11*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.74*
RIM-YEC - Net Present Value	*-$46.21*
RIM-YEC - Levelized Cost	*$0.3337/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$64.00
Incentive Amount in Year 1	$64.00
Assumed Program Administration Costs in Year 1	$64.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.94	$74.94
Discounted Cumulative Gross Energy Savings for 20 years	444 kWh	444 kWh
PC - Present Value of Benefits	$138.94	$138.94
PC - Present Value of Costs	$64.00	$64.00
PC - Benefit/Cost Ratio	2.17	2.17
PC - Net Present Value	$74.94	$74.94
PC - Levelized Cost	$0.1441/kWh	$0.1441/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$74.94	$74.94
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
RIM - Present Value of Benefits	$118.12	$118.12
RIM - Present Value of Costs	$202.94	$138.94
RIM - Benefit/Cost Ratio	0.6	0 9
RIM - Net Present Value	-$84.83	-$20.83
RIM - Levelized Cost	$0.4189/kWh	$0.2868/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
TRC - Present Value of Benefits	$118.12	$118.12
TRC - Present Value of Costs	$128.00	$64.00
TRC - Benefit/Cost Ratio	0.92	1.8
TRC - Net Present Value	-$9.88	$54.12
TRC - Levelized Cost	$0 2642/kWh	$0.1321/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
PAC - Present Value of Benefits	$118.12	$118.12
PAC - Present Value of Costs	$128.00	$64.00
PAC - Benefit/Cost Ratio	0.9	1.8
PAC - Net Present Value	-$9.88	$54.12
PAC - Levelized Cost	$0 2642/kWh	$0.1321/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM632

Inputs - Measure Considerations	
Measure Name:	Pilot LED PAR38 Bulbs
Incentive Amount:	$53.00
Measure/Project Cost:	$53.00
Gross Consumption Savings:	55 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	60 kWh/yr
Gross Demand Savings:	.02 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$7.99
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	106%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.94
PC - Net Present Value	$103.05
PC - Levelized Cost	$0.0868/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.78*
RIM - Net Present Value	*-$46.63*
RIM - Levelized Cost	*$0.3138/kWh*
TRC - Benefit/Cost Ratio	1.53
TRC - Net Present Value	$56.41
TRC - Levelized Cost	$0.1591/kWh
PAC - Benefit/Cost Ratio	*1.53*
PAC - Net Present Value	*$56.41*
PAC - Levelized Cost	*$0.1591/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$35.90*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.04*
RIM-YEC - Net Present Value	*$6.46*
RIM-YEC - Levelized Cost	*$0.2364/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$53.00
Incentive Amount in Year 1	$53.00
Assumed Program Administration Costs in Year 1	$53.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$103.05	$103.05
Discounted Cumulative Gross Energy Savings for 20 years	611 kWh	611 kWh
PC - Present Value of Benefits	$156.05	$156.05
PC - Present Value of Costs	$53.00	$53.00
PC - Benefit/Cost Ratio	2.94	2.94
PC - Net Present Value	$103.05	$103.05
PC - Levelized Cost	$0.0868/kWh	$0.0868/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$103.05	$103.05
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
RIM - Present Value of Benefits	$162.41	$162.41
RIM - Present Value of Costs	$209.05	$156.05
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$46.63	$6.37
RIM - Levelized Cost	$0 3138/kWh	$0.2342/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
TRC - Present Value of Benefits	$162.41	$162.41
TRC - Present Value of Costs	$106.00	$53.00
TRC - Benefit/Cost Ratio	1.53	3.1
TRC - Net Present Value	$56.41	$109.41
TRC - Levelized Cost	$0.1591/kWh	$0.0796/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
PAC - Present Value of Benefits	$162.41	$162.41
PAC - Present Value of Costs	$106.00	$53.00
PAC - Benefit/Cost Ratio	1.5	3.1
PAC - Net Present Value	$56.41	$109.41
PAC - Levelized Cost	$0.1591/kWh	$0.0796/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM442

Inputs - Measure Considerations	
Measure Name:	Pilot Spot or Task Lighting
Incentive Amount:	$25.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	43.62 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	0.015562 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	81%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.87
PC - Net Present Value	$46.76
PC - Levelized Cost	$0.0841/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.76*
RIM - Net Present Value	*-$23.06*
RIM - Levelized Cost	*$0.2984/kWh*
TRC - Benefit/Cost Ratio	1.47
TRC - Net Present Value	$23.71
TRC - Levelized Cost	$0.1542/kWh
PAC - Benefit/Cost Ratio	*1.47*
PAC - Net Present Value	*$23.71*
PAC - Levelized Cost	*$0.1542/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$16.91*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$0.97*
RIM-YEC - Levelized Cost	*$0.2306/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$25.00
Assumed Program Administration Costs in Year 1	$25.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$46.76	$46.76
Discounted Cumulative Gross Energy Savings for 10 years	297 kWh	297 kWh
PC - Present Value of Benefits	$71.76	$71.76
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.87	2.87
PC - Net Present Value	$46.76	$46.76
PC - Levelized Cost	$0.0841/kWh	$0.0841/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$46.76	$46.76
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
RIM - Present Value of Benefits	$73.71	$73.71
RIM - Present Value of Costs	$96.76	$71.76
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$23.06	$1.94
RIM - Levelized Cost	$0 2984/kWh	$0.2213/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
TRC - Present Value of Benefits	$73.71	$73.71
TRC - Present Value of Costs	$50.00	$25.00
TRC - Benefit/Cost Ratio	1.47	2 9
TRC - Net Present Value	$23.71	$48.71
TRC - Levelized Cost	$0.1542/kWh	$0.0771/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
PAC - Present Value of Benefits	$73.71	$73.71
PAC - Present Value of Costs	$50.00	$25.00
PAC - Benefit/Cost Ratio	1.5	2 9
PAC - Net Present Value	$23.71	$48.71
PAC - Levelized Cost	$0.1542/kWh	$0.0771/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM092

Inputs - Measure Considerations	
Measure Name:	Pilot Ultra Low-flow Showerheads
Incentive Amount:	$16.01
Measure/Project Cost:	$16.01
Gross Consumption Savings:	325 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	354 kWh/yr
Gross Demand Savings:	.116 kW
Gross Demand Savings w/ T&D losses:	.126 kW
Participant's Savings on Year 1:	$47.22
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	1033%
Suggested Program Cost (% of Incentive):	1033%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	24.73
PC - Net Present Value	$379.96
PC - Levelized Cost	$0.0066/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.07*
RIM - Net Present Value	*$37.49*
RIM - Levelized Cost	*$0.2131/kWh*
TRC - Benefit/Cost Ratio	3.30
TRC - Net Present Value	$417.46
TRC - Levelized Cost	$0.0689/kWh
PAC - Benefit/Cost Ratio	*3.30*
PAC - Net Present Value	*$417.46*
PAC - Levelized Cost	*$0.0689/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$137.43*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.53*
RIM-YEC - Net Present Value	*$216.99*
RIM-YEC - Levelized Cost	*$0.1486/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$16.01
Incentive Amount in Year 1	$16.01
Assumed Program Administration Costs in Year 1	$165.39
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$379.96	$379.96
Discounted Cumulative Gross Energy Savings for 10 years	2,416 kWh	2,416 kWh
PC - Present Value of Benefits	$395.97	$395.97
PC - Present Value of Costs	$16.01	$16.01
PC - Benefit/Cost Ratio	24.73	24.73
PC - Net Present Value	$379.96	$379.96
PC - Levelized Cost	$0.0066/kWh	$0.0066/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$379.96	$379.96
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
RIM - Present Value of Benefits	$598.86	$598.86
RIM - Present Value of Costs	$561.36	$395.97
RIM - Benefit/Cost Ratio	1.1	1 5
RIM - Net Present Value	$37.49	$202.89
RIM - Levelized Cost	$0 2131/kWh	$0.1503/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
TRC - Present Value of Benefits	$598.86	$598.86
TRC - Present Value of Costs	$181.40	$16.01
TRC - Benefit/Cost Ratio	3.30	37.4
TRC - Net Present Value	$417.46	$582.85
TRC - Levelized Cost	$0.0689/kWh	$0.0061/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
PAC - Present Value of Benefits	$598.86	$598.86
PAC - Present Value of Costs	$181.40	$16.01
PAC - Benefit/Cost Ratio	3.3	37.4
PAC - Net Present Value	$417.46	$582.85
PAC - Levelized Cost	$0.0689/kWh	$0.0061/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM112

Inputs - Measure Considerations	
Measure Name:	Pilot Smart, Surge Protected Power Bars for PCs and TVs
Incentive Amount:	$50.00
Measure/Project Cost:	$50.00
Gross Consumption Savings:	68 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	74 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.85
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	69%
Suggested Program Cost (% of Incentive):	69%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.58
PC - Net Present Value	$79.24
PC - Levelized Cost	$0.0992/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.76*
RIM - Net Present Value	*-$38.84*
RIM - Levelized Cost	*$0.2980/kWh*
TRC - Benefit/Cost Ratio	1.48
TRC - Net Present Value	$40.40
TRC - Levelized Cost	$0.1538/kWh
PAC - Benefit/Cost Ratio	*1.48*
PAC - Net Present Value	*$40.40*
PAC - Levelized Cost	*$0.1538/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.66*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$1.41*
RIM-YEC - Levelized Cost	*$0.2302/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$50.00
Incentive Amount in Year 1	$50.00
Assumed Program Administration Costs in Year 1	$34.49
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$79.24	$79.24
Discounted Cumulative Gross Energy Savings for 10 years	504 kWh	504 kWh
PC - Present Value of Benefits	$129.24	$129.24
PC - Present Value of Costs	$50.00	$50.00
PC - Benefit/Cost Ratio	2.58	2.58
PC - Net Present Value	$79.24	$79.24
PC - Levelized Cost	$0.0992/kWh	$0.0992/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$79.24	$79.24
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
RIM - Present Value of Benefits	$124.89	$124.89
RIM - Present Value of Costs	$163.74	$129.24
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$38.84	-$4.35
RIM - Levelized Cost	$0 2980/kWh	$0.2352/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
TRC - Present Value of Benefits	$124.89	$124.89
TRC - Present Value of Costs	$84.49	$50.00
TRC - Benefit/Cost Ratio	1.48	2 5
TRC - Net Present Value	$40.40	$74.89
TRC - Levelized Cost	$0.1538/kWh	$0.0910/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
PAC - Present Value of Benefits	$124.89	$124.89
PAC - Present Value of Costs	$84.49	$50.00
PAC - Benefit/Cost Ratio	1.5	2 5
PAC - Net Present Value	$40.40	$74.89
PAC - Levelized Cost	$0.1538/kWh	$0.0910/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM182

Inputs - Measure Considerations	
Measure Name:	Pilot DHW Tank Insulation
Incentive Amount:	$37.58
Measure/Project Cost:	$37.58
Gross Consumption Savings:	62 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	68 kWh/yr
Gross Demand Savings:	.022 kW
Gross Demand Savings w/ T&D losses:	.024 kW
Participant's Savings on Year 1:	$9.01
Measure Lifetime:	14 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	118%
Suggested Program Cost (% of Incentive):	118%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.47
PC - Net Present Value	$92.64
PC - Levelized Cost	$0.0658/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.84*
RIM - Net Present Value	*-$28.38*
RIM - Levelized Cost	*$0.2798/kWh*
TRC - Benefit/Cost Ratio	1.79
TRC - Net Present Value	$64.26
TRC - Levelized Cost	$0.1312/kWh
PAC - Benefit/Cost Ratio	*1.79*
PAC - Net Present Value	*$64.26*
PAC - Levelized Cost	*$0.1312/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$32.97*
RIM-YECL - Levelized Cost	*$0.1482/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.12*
RIM-YEC - Net Present Value	*$17.04*
RIM-YEC - Levelized Cost	*$0.2092/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.58
Incentive Amount in Year 1	$37.58
Assumed Program Administration Costs in Year 1	$44.17
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 14 years	$92.64	$92.64
Discounted Cumulative Gross Energy Savings for 14 years	571 kWh	571 kWh
PC - Present Value of Benefits	$130.22	$130.22
PC - Present Value of Costs	$37.58	$37.58
PC - Benefit/Cost Ratio	3.47	3.47
PC - Net Present Value	$92.64	$92.64
PC - Levelized Cost	$0.0658/kWh	$0.0658/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Present Value of Lost Revenues for 14 years	$92.64	$92.64
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
RIM - Present Value of Benefits	$146.01	$146.01
RIM - Present Value of Costs	$174.39	$130.22
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$28.38	$15.79
RIM - Levelized Cost	$0 2798/kWh	$0.2090/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
TRC - Present Value of Benefits	$146.01	$146.01
TRC - Present Value of Costs	$81.75	$37.58
TRC - Benefit/Cost Ratio	1.79	3 9
TRC - Net Present Value	$64.26	$108.43
TRC - Levelized Cost	$0.1312/kWh	$0.0603/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
PAC - Present Value of Benefits	$146.01	$146.01
PAC - Present Value of Costs	$81.75	$37.58
PAC - Benefit/Cost Ratio	1.8	3 9
PAC - Net Present Value	$64.26	$108.43
PAC - Levelized Cost	$0.1312/kWh	$0.0603/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM202

Inputs - Measure Considerations	
Measure Name:	Pilot DHW Pipe Insulation
Incentive Amount:	$0.79
Measure/Project Cost:	$0.79
Gross Consumption Savings:	34 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	37 kWh/yr
Gross Demand Savings:	.012 kW
Gross Demand Savings w/ T&D losses:	.013 kW
Participant's Savings on Year 1:	$4.94
Measure Lifetime:	15 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	3285%
Suggested Program Cost (% of Incentive):	3285%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	68.39
PC - Net Present Value	$53.23
PC - Levelized Cost	$0.0024/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$3.92*
RIM - Levelized Cost	*$0.2249/kWh*
TRC - Benefit/Cost Ratio	3.14
TRC - Net Present Value	$57.16
TRC - Levelized Cost	$0.0752/kWh
PAC - Benefit/Cost Ratio	*3.14*
PAC - Net Present Value	*$57.16*
PAC - Levelized Cost	*$0.0752/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$18.88*
RIM-YECL - Levelized Cost	*$0.1492/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.51*
RIM-YEC - Net Present Value	*$30.25*
RIM-YEC - Levelized Cost	*$0.1567/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.79
Incentive Amount in Year 1	$0.79
Assumed Program Administration Costs in Year 1	$25.95
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 15 years	$53.23	$53.23
Discounted Cumulative Gross Energy Savings for 15 years	326 kWh	326 kWh
PC - Present Value of Benefits	$54.02	$54.02
PC - Present Value of Costs	$0.79	$0.79
PC - Benefit/Cost Ratio	68.39	68.39
PC - Net Present Value	$53.23	$53.23
PC - Levelized Cost	$0.0024/kWh	$0.0024/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Present Value of Lost Revenues for 15 years	$53.23	$53.23
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
RIM - Present Value of Benefits	$83.90	$83.90
RIM - Present Value of Costs	$79.98	$54.02
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$3.92	$29.88
RIM - Levelized Cost	$0 2249/kWh	$0.1519/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
TRC - Present Value of Benefits	$83.90	$83.90
TRC - Present Value of Costs	$26.74	$0.79
TRC - Benefit/Cost Ratio	3.14	106 2
TRC - Net Present Value	$57.16	$83.11
TRC - Levelized Cost	$0.0752/kWh	$0.0022/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
PAC - Present Value of Benefits	$83.90	$83.90
PAC - Present Value of Costs	$26.74	$0.79
PAC - Benefit/Cost Ratio	3.1	106 2
PAC - Net Present Value	$57.16	$83.11
PAC - Levelized Cost	$0.0752/kWh	$0.0022/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM482

Inputs - Measure Considerations	
Measure Name:	Pilot Motion Detectors - Indoor and Outdoor
Incentive Amount:	$22.94
Measure/Project Cost:	$22.94
Gross Consumption Savings:	66 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	72 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.59
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	146%
Suggested Program Cost (% of Incentive):	146%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.36
PC - Net Present Value	$77.15
PC - Levelized Cost	$0.0468/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.91*
RIM - Net Present Value	*-$12.07*
RIM - Levelized Cost	*$0.2499/kWh*
TRC - Benefit/Cost Ratio	2.15
TRC - Net Present Value	$65.08
TRC - Levelized Cost	$0.1057/kWh
PAC - Benefit/Cost Ratio	*2.15*
PAC - Net Present Value	*$65.08*
PAC - Levelized Cost	*$0.1057/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$27.90*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.24*
RIM-YEC - Net Present Value	*$24.37*
RIM-YEC - Levelized Cost	*$0.1840/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$22.94
Incentive Amount in Year 1	$22.94
Assumed Program Administration Costs in Year 1	$33.58
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$77.15	$77.15
Discounted Cumulative Gross Energy Savings for 10 years	490 kWh	490 kWh
PC - Present Value of Benefits	$100.09	$100.09
PC - Present Value of Costs	$22.94	$22.94
PC - Benefit/Cost Ratio	4.36	4.36
PC - Net Present Value	$77.15	$77.15
PC - Levelized Cost	$0.0468/kWh	$0.0468/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$77.15	$77.15
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
RIM - Present Value of Benefits	$121.60	$121.60
RIM - Present Value of Costs	$133.67	$100.09
RIM - Benefit/Cost Ratio	0.9	1 2
RIM - Net Present Value	-$12.07	$21.51
RIM - Levelized Cost	$0 2499/kWh	$0.1871/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
TRC - Present Value of Benefits	$121.60	$121.60
TRC - Present Value of Costs	$56.52	$22.94
TRC - Benefit/Cost Ratio	2.15	5 3
TRC - Net Present Value	$65.08	$98.66
TRC - Levelized Cost	$0.1057/kWh	$0.0429/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
PAC - Present Value of Benefits	$121.60	$121.60
PAC - Present Value of Costs	$56.52	$22.94
PAC - Benefit/Cost Ratio	2.2	5 3
PAC - Net Present Value	$65.08	$98.66
PAC - Levelized Cost	$0.1057/kWh	$0.0429/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM152

Inputs - Measure Considerations	
Measure Name:	Pilot Auto Heater Timers
Incentive Amount:	$37.50
Measure/Project Cost:	$37.50
Gross Consumption Savings:	130 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	142 kWh/yr
Gross Demand Savings:	0.05 kW
Gross Demand Savings w/ T&D losses:	0.05 kW
Participant's Savings on Year 1:	$18.86
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	176%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	5.05
PC - Net Present Value	$151.74
PC - Levelized Cost	$0.0389/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$12.42*
RIM - Levelized Cost	*$0.2155/kWh*
TRC - Benefit/Cost Ratio	3.19
TRC - Net Present Value	$164.16
TRC - Levelized Cost	$0.0713/kWh
PAC - Benefit/Cost Ratio	*3.19*
PAC - Net Present Value	*$164.16*
PAC - Levelized Cost	*$0.0713/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$54.89*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.51*
RIM-YEC - Net Present Value	*$84.11*
RIM-YEC - Levelized Cost	*$0.1510/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.50
Incentive Amount in Year 1	$37.50
Assumed Program Administration Costs in Year 1	$37.50
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$151.74	$151.74
Discounted Cumulative Gross Energy Savings for 10 years	965 kWh	965 kWh
PC - Present Value of Benefits	$189.24	$189.24
PC - Present Value of Costs	$37.50	$37.50
PC - Benefit/Cost Ratio	5.05	5.05
PC - Net Present Value	$151.74	$151.74
PC - Levelized Cost	$0.0389/kWh	$0.0389/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$151.74	$151.74
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
RIM - Present Value of Benefits	$239.16	$239.16
RIM - Present Value of Costs	$226.74	$189.24
RIM - Benefit/Cost Ratio	1.1	1 3
RIM - Net Present Value	$12.42	$49.92
RIM - Levelized Cost	$0 2155/kWh	$0.1799/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
TRC - Present Value of Benefits	$239.16	$239.16
TRC - Present Value of Costs	$75.00	$37.50
TRC - Benefit/Cost Ratio	3.19	6.4
TRC - Net Present Value	$164.16	$201.66
TRC - Levelized Cost	$0.0713/kWh	$0.0356/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
PAC - Present Value of Benefits	$239.16	$239.16
PAC - Present Value of Costs	$75.00	$37.50
PAC - Benefit/Cost Ratio	3.2	6.4
PAC - Net Present Value	$164.16	$201.66
PAC - Levelized Cost	$0.0713/kWh	$0.0356/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM142

Inputs - Measure Considerations	
Measure Name:	Pilot Prog. Thermostats (Central)
Incentive Amount:	$62.50
Measure/Project Cost:	$62.50
Gross Consumption Savings:	827 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	902 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.322 kW
Participant's Savings on Year 1:	$120.16
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	741%
Suggested Program Cost (% of Incentive):	741%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	17.63
PC - Net Present Value	$1,039.26
PC - Levelized Cost	$0.0095/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$73.27*
RIM - Levelized Cost	*$0.2189/kWh*
TRC - Benefit/Cost Ratio	3.12
TRC - Net Present Value	$1,112.53
TRC - Levelized Cost	$0.0735/kWh
PAC - Benefit/Cost Ratio	*3.12*
PAC - Net Present Value	*$1,112.53*
PAC - Levelized Cost	*$0.0735/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$374.34*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.50*
RIM-YEC - Net Present Value	*$568.97*
RIM-YEC - Levelized Cost	*$0.1535/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$62.50
Incentive Amount in Year 1	$62.50
Assumed Program Administration Costs in Year 1	$462.95
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,039 26	$1,039.26
Discounted Cumulative Gross Energy Savings for 11 years	6,556 kWh	6,556 kWh
PC - Present Value of Benefits	$1,101.76	$1,101.76
PC - Present Value of Costs	$62.50	$62.50
PC - Benefit/Cost Ratio	17.63	17.63
PC - Net Present Value	$1,039.26	$1,039.26
PC - Levelized Cost	$0.0095/kWh	$0.0095/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,039.26	$1,039.26
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
RIM - Present Value of Benefits	$1,637.98	$1,637.98
RIM - Present Value of Costs	$1,564.70	$1,101.76
RIM - Benefit/Cost Ratio	1.0	1 5
RIM - Net Present Value	$73.27	$536.22
RIM - Levelized Cost	$0 2189/kWh	$0.1541/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
TRC - Present Value of Benefits	$1,637.98	$1,637.98
TRC - Present Value of Costs	$525.45	$62.50
TRC - Benefit/Cost Ratio	3.12	26 2
TRC - Net Present Value	$1,112.53	$1,575.48
TRC - Levelized Cost	$0.0735/kWh	$0.0087/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
PAC - Present Value of Benefits	$1,637.98	$1,637.98
PAC - Present Value of Costs	$525.45	$62.50
PAC - Benefit/Cost Ratio	3.1	26 2
PAC - Net Present Value	$1,112.53	$1,575.48
PAC - Levelized Cost	$0.0735/kWh	$0.0087/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM212

Inputs - Measure Considerations	
Measure Name:	Pilot Prog. Thermostats
Incentive Amount:	$285.43
Measure/Project Cost:	$285.43
Gross Consumption Savings:	826 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	901 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.321 kW
Participant's Savings on Year 1:	$120.02
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	162%
Suggested Program Cost (% of Incentive):	162%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.64
PC - Net Present Value	$1,038.00
PC - Levelized Cost	$0.0436/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.92*
RIM - Net Present Value	*-$149.82*
RIM - Levelized Cost	*$0.2501/kWh*
TRC - Benefit/Cost Ratio	2.19
TRC - Net Present Value	$888.18
TRC - Levelized Cost	$0.1047/kWh
PAC - Benefit/Cost Ratio	*2.19*
PAC - Net Present Value	*$888.18*
PAC - Levelized Cost	*$0.1047/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$373.89*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.25*
RIM-YEC - Net Present Value	*$345.28*
RIM-YEC - Levelized Cost	*$0.1833/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$285.43
Incentive Amount in Year 1	$285.43
Assumed Program Administration Costs in Year 1	$462.39
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Gross Energy Savings for 11 years	6,548 kWh	6,548 kWh
PC - Present Value of Benefits	$1,323.43	$1,323.43
PC - Present Value of Costs	$285.43	$285.43
PC - Benefit/Cost Ratio	4.64	4.64
PC - Net Present Value	$1,038.00	$1,038.00
PC - Levelized Cost	$0.0436/kWh	$0.0436/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
RIM - Present Value of Benefits	$1,636.00	$1,636.00
RIM - Present Value of Costs	$1,785.82	$1,323.43
RIM - Benefit/Cost Ratio	0.9	1 2
RIM - Net Present Value	-$149.82	$312.57
RIM - Levelized Cost	$0 2501/kWh	$0.1853/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
TRC - Present Value of Benefits	$1,636.00	$1,636.00
TRC - Present Value of Costs	$747.82	$285.43
TRC - Benefit/Cost Ratio	2.19	5.7
TRC - Net Present Value	$888.18	$1,350.57
TRC - Levelized Cost	$0.1047/kWh	$0.0400/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
PAC - Present Value of Benefits	$1,636.00	$1,636.00
PAC - Present Value of Costs	$747.82	$285.43
PAC - Benefit/Cost Ratio	2.2	5.7
PAC - Net Present Value	$888.18	$1,350.57
PAC - Levelized Cost	$0.1047/kWh	$0.0400/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM062

Inputs - Measure Considerations	
Measure Name:	Pilot E-Star TVs
Incentive Amount:	$1,125.00
Measure/Project Cost:	$1,125.00
Gross Consumption Savings:	69 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	75 kWh/yr
Gross Demand Savings:	.025 kW
Gross Demand Savings w/ T&D losses:	.027 kW
Participant's Savings on Year 1:	$10.03
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	3%
Suggested Program Cost (% of Incentive):	3%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.07
PC - Net Present Value	$80.67
PC - Levelized Cost	$2.1935/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.10*
RIM - Net Present Value	*-$1,113.64*
RIM - Levelized Cost	*$2.2185/kWh*
TRC - Benefit/Cost Ratio	0.11
TRC - Net Present Value	-$1,032.97
TRC - Levelized Cost	$2.0743/kWh
PAC - Benefit/Cost Ratio	*0.11*
PAC - Net Present Value	*-$1,032.97*
PAC - Levelized Cost	*$2.0743/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$29.18*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.11*
RIM-YEC - Net Present Value	*-$1,075.53*
RIM-YEC - Levelized Cost	*$2.0737/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$1,125.00
Incentive Amount in Year 1	$1,125.00
Assumed Program Administration Costs in Year 1	$35.11
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$80.67	$80.67
Discounted Cumulative Gross Energy Savings for 10 years	513 kWh	513 kWh
PC - Present Value of Benefits	$1,205.67	$1,205.67
PC - Present Value of Costs	$1,125.00	$1,125.00
PC - Benefit/Cost Ratio	1.07	1.07
PC - Net Present Value	$80.67	$80.67
PC - Levelized Cost	$2.1935/kWh	$2.1935/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$80.67	$80.67
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
RIM - Present Value of Benefits	$127.14	$127.14
RIM - Present Value of Costs	$1,240.78	$1,205.67
RIM - Benefit/Cost Ratio	0.1	0.1
RIM - Net Present Value	-$1,113.64	-$1,078.53
RIM - Levelized Cost	$2 2185/kWh	$2.1557/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
TRC - Present Value of Benefits	$127.14	$127.14
TRC - Present Value of Costs	$1,160.11	$1,125.00
TRC - Benefit/Cost Ratio	0.11	0.1
TRC - Net Present Value	-$1,032 97	-$997.86
TRC - Levelized Cost	$2.0743/kWh	$2.0115/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
PAC - Present Value of Benefits	$127.14	$127.14
PAC - Present Value of Costs	$1,160.11	$1,125.00
PAC - Benefit/Cost Ratio	0.1	0.1
PAC - Net Present Value	-$1,032 97	-$997.86
PAC - Levelized Cost	$2.0743/kWh	$2.0115/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM082

Inputs - Measure Considerations	
Measure Name:	Pilot ESTAR Printers and Fax
Incentive Amount:	$200.00
Measure/Project Cost:	$200.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.61
Measure Lifetime:	6 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	5%
Suggested Program Cost (% of Incentive):	5%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.12
PC - Net Present Value	$24.48
PC - Levelized Cost	$1.2431/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.16*
RIM - Net Present Value	*-$195.59*
RIM - Levelized Cost	*$1.3347/kWh*
TRC - Benefit/Cost Ratio	0.18
TRC - Net Present Value	-$171.11
TRC - Levelized Cost	$1.1952/kWh
PAC - Benefit/Cost Ratio	*0.18*
PAC - Net Present Value	*-$171.11*
PAC - Levelized Cost	*$1.1952/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.01*
RIM-YECL - Levelized Cost	*$0.1394/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.18*
RIM-YEC - Net Present Value	*-$184.49*
RIM-YEC - Levelized Cost	*$1.2468/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$200.00
Incentive Amount in Year 1	$200.00
Assumed Program Administration Costs in Year 1	$9.69
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 6 years	$24.48	$24.48
Discounted Cumulative Gross Energy Savings for 6 years	161 kWh	161 kWh
PC - Present Value of Benefits	$224.48	$224.48
PC - Present Value of Costs	$200.00	$200.00
PC - Benefit/Cost Ratio	1.12	1.12
PC - Net Present Value	$24.48	$24.48
PC - Levelized Cost	$1 2431/kWh	$1.2431/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Present Value of Lost Revenues for 6 years	$24.48	$24.48
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
RIM - Present Value of Benefits	$38.58	$38.58
RIM - Present Value of Costs	$234.17	$224.48
RIM - Benefit/Cost Ratio	0.2	0 2
RIM - Net Present Value	-$195 59	-$185.90
RIM - Levelized Cost	$1 3347/kWh	$1.2795/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
TRC - Present Value of Benefits	$38.58	$38.58
TRC - Present Value of Costs	$209.69	$200.00
TRC - Benefit/Cost Ratio	0.18	0 2
TRC - Net Present Value	-$171.11	-$161.42
TRC - Levelized Cost	$1.1952/kWh	$1.1399/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
PAC - Present Value of Benefits	$38.58	$38.58
PAC - Present Value of Costs	$209.69	$200.00
PAC - Benefit/Cost Ratio	0.2	0 2
PAC - Net Present Value	-$171.11	-$161.42
PAC - Levelized Cost	$1.1952/kWh	$1.1399/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM032

Inputs - Measure Considerations	
Measure Name:	Pilot Cold Temp Heat Pumps
Incentive Amount:	$5,000.00
Measure/Project Cost:	$8,498.44
Gross Consumption Savings:	6,780 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7,394 kWh/yr
Gross Demand Savings:	2.42 kW
Gross Demand Savings w/ T&D losses:	2.64 kW
Participant's Savings on Year 1:	$985.13
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	138%
Suggested Program Cost (% of Incentive):	138%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.08
PC - Net Present Value	$9,204.38
PC - Levelized Cost	$0.1129/kWh
Simple Payback w/ Incentive (yr)	3.6 yr
RIM - Benefit/Cost Ratio	*0.81*
RIM - Net Present Value	*-$4,582.55*
RIM - Levelized Cost	*$0.2996/kWh*
TRC - Benefit/Cost Ratio	1.30
TRC - Net Present Value	$4,621.84
TRC - Levelized Cost	$0.1875/kWh
PAC - Benefit/Cost Ratio	*1.68*
PAC - Net Present Value	*$8,120.28*
PAC - Levelized Cost	*$0.1449/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$4,425.66*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.10*
RIM-YEC - Net Present Value	*$1,961.99*
RIM-YEC - Levelized Cost	*$0.2232/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8,498.44
Incentive Amount in Year 1	$5,000.00
Assumed Program Administration Costs in Year 1	$6,900.67
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Gross Energy Savings for 20 years	75,306 kWh	75,306 kWh
PC - Present Value of Benefits	$17,702.82	$17,702.82
PC - Present Value of Costs	$8,498.44	$8,498.44
PC - Benefit/Cost Ratio	2.08	2.08
PC - Net Present Value	$9,204.38	$9,204.38
PC - Levelized Cost	$0.1129/kWh	$0.1129/kWh
Simple Payback with Incentive	3.6 yr	3.6 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
RIM - Present Value of Benefits	$20,020.95	$20,020.95
RIM - Present Value of Costs	$24,603.49	$17,702.82
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$4,582.55	$2,318.12
RIM - Levelized Cost	$0 2996/kWh	$0.2156/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
TRC - Present Value of Benefits	$20,020 95	$20,020.95
TRC - Present Value of Costs	$15,399.11	$8,498.44
TRC - Benefit/Cost Ratio	1.30	2.4
TRC - Net Present Value	$4,621.84	$11,522.51
TRC - Levelized Cost	$0.1875/kWh	$0.1035/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
PAC - Present Value of Benefits	$20,020 95	$20,020.95
PAC - Present Value of Costs	$11,900.67	$5,000.00
PAC - Benefit/Cost Ratio	1.7	4.0
PAC - Net Present Value	$8,120.28	$15,020.95
PAC - Levelized Cost	$0.1449/kWh	$0.0609/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM372

Inputs - Measure Considerations	
Measure Name:	Pilot Ground Heat Pumps - Closed
Incentive Amount:	$9,000.00
Measure/Project Cost:	$34,245.24
Gross Consumption Savings:	8,605 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	9,384 kWh/yr
Gross Demand Savings:	3.07 kW
Gross Demand Savings w/ T&D losses:	3.35 kW
Participant's Savings on Year 1:	$1,250.31
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	97%
Suggested Program Cost (% of Incentive):	97%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.73
PC - Net Present Value	-$9,123.14
PC - Levelized Cost	$0.3583/kWh
Simple Payback w/ Incentive (yr)	20.2 yr
RIM - Benefit/Cost Ratio	*0.75*
RIM - Net Present Value	*-$8,470.18*
RIM - Levelized Cost	*$0.3251/kWh*
TRC - Benefit/Cost Ratio	0.59
TRC - Net Present Value	-$17,593.32
TRC - Levelized Cost	$0.4126/kWh
PAC - Benefit/Cost Ratio	*1.43*
PAC - Net Present Value	*$7,651.91*
PAC - Levelized Cost	*$0.1704/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$5,616.94*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$164.02*
RIM-YEC - Levelized Cost	*$0.2468/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$34,245 24
Incentive Amount in Year 1	$9,000.00
Assumed Program Administration Costs in Year 1	$8,758.15
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Gross Energy Savings for 20 years	95,576 kWh	95,576 kWh
PC - Present Value of Benefits	$25,122.09	$25,122.09
PC - Present Value of Costs	$34,245 24	$34,245.24
PC - Benefit/Cost Ratio	0.73	0.73
PC - Net Present Value	-$9,123.14	-$9,123.14
PC - Levelized Cost	$0 3583/kWh	$0.3583/kWh
Simple Payback with Incentive	20 2 yr	20.2 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
RIM - Present Value of Benefits	$25,410.06	$25,410.06
RIM - Present Value of Costs	$33,880.24	$25,122.09
RIM - Benefit/Cost Ratio	0.7	1.0
RIM - Net Present Value	-$8,470.18	$287.97
RIM - Levelized Cost	$0 3251/kWh	$0.2410/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
TRC - Present Value of Benefits	$25,410.06	$25,410.06
TRC - Present Value of Costs	$43,003 39	$34,245.24
TRC - Benefit/Cost Ratio	0.59	0.7
TRC - Net Present Value	-$17,593 32	-$8,835.17
TRC - Levelized Cost	$0.4126/kWh	$0.3286/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
PAC - Present Value of Benefits	$25,410.06	$25,410.06
PAC - Present Value of Costs	$17,758.15	$9,000.00
PAC - Benefit/Cost Ratio	1.4	2.8
PAC - Net Present Value	$7,651.91	$16,410.06
PAC - Levelized Cost	$0.1704/kWh	$0.0863/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM03

Inputs - Measure Considerations	
Measure Name:	Cold Temp Heat Pumps
Incentive Amount:	$2,500.00
Measure/Project Cost:	$8,498.44
Gross Consumption Savings:	6,780 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7,394 kWh/yr
Gross Demand Savings:	2.42 kW
Gross Demand Savings w/ T&D losses:	2.64 kW
Participant's Savings on Year 1:	$985.13
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	216%
Suggested Program Cost (% of Incentive):	216%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.79
PC - Net Present Value	$6,704.38
PC - Levelized Cost	$0.1129/kWh
Simple Payback w/ Incentive (yr)	6.1 yr
RIM - Benefit/Cost Ratio	*0.97*
RIM - Net Present Value	*-$577.12*
RIM - Levelized Cost	*$0.2508/kWh*
TRC - Benefit/Cost Ratio	1.44
TRC - Net Present Value	$6,127.27
TRC - Levelized Cost	$0.1692/kWh
PAC - Benefit/Cost Ratio	*2.54*
PAC - Net Present Value	*$12,125.71*
PAC - Levelized Cost	*$0.0961/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$4,425.66*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.38*
RIM-YEC - Net Present Value	*$5,967.42*
RIM-YEC - Levelized Cost	*$0.1780/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8,498.44
Incentive Amount in Year 1	$2,500.00
Assumed Program Administration Costs in Year 1	$5,395 24
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Gross Energy Savings for 20 years	75,306 kWh	75,306 kWh
PC - Present Value of Benefits	$15,202.82	$15,202.82
PC - Present Value of Costs	$8,498.44	$8,498.44
PC - Benefit/Cost Ratio	1.79	1.79
PC - Net Present Value	$6,704.38	$6,704.38
PC - Levelized Cost	$0.1129/kWh	$0.1129/kWh
Simple Payback with Incentive	6.1 yr	6.1 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
RIM - Present Value of Benefits	$20,020.95	$20,020.95
RIM - Present Value of Costs	$20,598.06	$15,202.82
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	-$577.12	$4,818.12
RIM - Levelized Cost	$0 2508/kWh	$0.1851/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
TRC - Present Value of Benefits	$20,020 95	$20,020.95
TRC - Present Value of Costs	$13,893.68	$8,498.44
TRC - Benefit/Cost Ratio	1.44	2.4
TRC - Net Present Value	$6,127.27	$11,522.51
TRC - Levelized Cost	$0.1692/kWh	$0.1035/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
PAC - Present Value of Benefits	$20,020 95	$20,020.95
PAC - Present Value of Costs	$7,895.24	$2,500.00
PAC - Benefit/Cost Ratio	2.5	8.0
PAC - Net Present Value	$12,125.71	$17,520.95
PAC - Levelized Cost	$0.0961/kWh	$0.0304/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM37

Inputs - Measure Considerations	
Measure Name:	Ground Heat Pumps - Closed
Incentive Amount:	$3,500.00
Measure/Project Cost:	$34,245.24
Gross Consumption Savings:	8,605 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	9,384 kWh/yr
Gross Demand Savings:	3.07 kW
Gross Demand Savings w/ T&D losses:	3.35 kW
Participant's Savings on Year 1:	$1,250.31
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	196%
Suggested Program Cost (% of Incentive):	196%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.57
PC - Net Present Value	-$14,623.14
PC - Levelized Cost	$0.3583/kWh
Simple Payback w/ Incentive (yr)	24.6 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$1,059.53*
RIM - Levelized Cost	*$0.2540/kWh*
TRC - Benefit/Cost Ratio	0.62
TRC - Net Present Value	-$15,682.67
TRC - Levelized Cost	$0.3943/kWh
PAC - Benefit/Cost Ratio	*2.46*
PAC - Net Present Value	*$15,062.57*
PAC - Levelized Cost	*$0.0993/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$5,616.94*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.36*
RIM-YEC - Net Present Value	*$7,246.63*
RIM-YEC - Levelized Cost	*$0.1809/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$34,245 24
Incentive Amount in Year 1	$3,500.00
Assumed Program Administration Costs in Year 1	$6,847 50
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Gross Energy Savings for 20 years	95,576 kWh	95,576 kWh
PC - Present Value of Benefits	$19,622.09	$19,622.09
PC - Present Value of Costs	$34,245 24	$34,245.24
PC - Benefit/Cost Ratio	0.57	0.57
PC - Net Present Value	-$14,623.14	-$14,623.14
PC - Levelized Cost	$0 3583/kWh	$0.3583/kWh
Simple Payback with Incentive	24.6 yr	24.6 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
RIM - Present Value of Benefits	$25,410.06	$25,410.06
RIM - Present Value of Costs	$26,469.59	$19,622.09
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	-$1,059.53	$5,787.97
RIM - Levelized Cost	$0 2540/kWh	$0.1883/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
TRC - Present Value of Benefits	$25,410.06	$25,410.06
TRC - Present Value of Costs	$41,092.74	$34,245.24
TRC - Benefit/Cost Ratio	0.62	0.7
TRC - Net Present Value	-$15,682.67	-$8,835.17
TRC - Levelized Cost	$0 3943/kWh	$0.3286/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
PAC - Present Value of Benefits	$25,410.06	$25,410.06
PAC - Present Value of Costs	$10,347 50	$3,500.00
PAC - Benefit/Cost Ratio	2.5	7 3
PAC - Net Present Value	$15,062.57	$21,910.06
PAC - Levelized Cost	$0.0993/kWh	$0.0336/kWh

YUB-YECL-28

Reference: General, Yukon Five Year Demand Side Management Plan

The Board wants to better understand some of the programs in the DSM plan

Request:

(a) Why do YEC and YECL have a scenario where government buildings are excluded?

(b) Please describe whether non-incentive costs for these programs are fixed costs (i.e. if no participants, then will the costs be the same?).

(c) Please describe whether the incentive costs for these programs are purely variable costs (i.e., if no participants, then will the costs will be zero?).

(d) For the programs involving rebates or some sort of cash incentive, what will happen to total costs if the participation rate is much higher than YEC and YECL anticipated? Do YEC and YECL have a cap on how much can be spent on these programs or how many participants will be accepted each year?

(e) What if the participation rate of these programs is much lower than YEC and YECL anticipated?

(f) For programs that involve providing the participant with a rebate or some sort of cash incentive, why do YEC and YECL have to provide such a rebate or incentive if the programs pass the "Participant Costs" test. If they are rational profit maximizing agents, will the participants/owners/managers not be willing to take on these activities independent of any incentive from YEC and YECL?

Response:

(a) During consultation, stakeholders provided input as to whether government accounts should be included or excluded from the DSM programs. The utilities analyzed both scenarios and determined there is a marginal increase in costs to deliver programs to government accounts. However, by providing programs to government accounts, a substantial electricity savings could be achieved. It

should be noted that government accounts include municipal, community, territorial, federal and First Nation governments. The utilities felt that due to the divide in stakeholder opinions, the decision as to whether government accounts should or should not be included in programs was best determined by the YUB.

Based on the marginal cost increase versus the substantial electricity savings, it is the utilities' opinion that government accounts should be allowed to participate in the DSM program. Each individual government account holder can choose how they then participate. The utilities request that the YUB select one scenario for implementation, with or without government accounts.

(b) Generally speaking, non-incentive costs related to the launch of the programs are fixed. Promotional or educational costs are notionally fixed, although they can be slowly ramped up or down to maximize cost-effectiveness. After the launch stage a large portion of non-incentive direct costs are marginal, i.e. if no participants, these costs will go down for the period as a result.

In addition, DSM staff costs are fixed as the utilities will not instantly hire and fire DSM staff in reaction to demand. However, based on early uptake numbers and market feedback, the utilities will be able to make medium- to long-term adjustments to the DSM staff to match a less- or more-than-expected number of transactions, ramping up or down the cost accordingly to maximize cost-effectiveness.

(c) Incentive costs are variable with the number of participants in that particular program, i.e. should there be zero participants, zero dollars will be spent on incentives.

(d) In the Program Portfolio *(*Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application*),* an estimated number of participants is forecast for each program. The estimate of participants was factored into the costs of each program. It is anticipated that during the implementation of the programs, the utilities would not exceed these participant numbers. However, the utilities require the ability to be flexible with programs. The utilities reserve the right to adjust the data inputs as necessary in accordance with market conditions. While program budgets are flexible, annual budgets will be respected. This process of program evaluation is outlined in the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1*.*

(e) The utilities have developed an Evaluation, Measurement and Verification Plan to allow for the flexibility to adjust programs as results are achieved. Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for more details.

(f) It should be noted that the Participant Cost Test is used to assess the cost effectiveness from the perspective of the participant after the application of the incentive, not before. Hurdles, barriers and program rationales are laid out in detail in the Evaluation, Measurement and Verification plans. Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for more details.

The question in 28(f) would be correct if markets and consumers were behaving in a perfectly rational manner from a financial standpoint, and if energy-efficiency innovations were adopted instantaneously as soon as they became economically viable. On both counts, this is not the case. Market failures, barriers and hurdles slow down the adoption of emerging cost-effective technologies and practices. Moreover, accelerating the penetration of cost-effective technologies and practices as compared to normal market adoption generates wealth for all ratepayers as illustrated by the positive TRC test by avoiding primary energy costs, and differing investments in generation, transmission and/or distribution capacity.

Many consumers do not purchase or invest in the most energy efficient option on their own because, for example:

- of the incremental initial cost of the conservation measure;
- the products don't have as much in-store visibility as base-case products;
- the sales people do not push these products as much because they are not familiar with them;
- consumers aren't provided with the information in a timely manner to make a choice;
- consumers don't invest the time to look into the new options;

- consumers don't trust the information that is being provided to them by the vendors; or

- consumers make decisions based on habits rather than a careful comparison between options.

Rebates/incentives are effective at generating incremental savings because, for example:

- Notionally, rebates/incentives get results by offsetting the initial cost hurdle, and/or lowering the simple payback or knocking down the risk of "trying" the technology;

- Even without an actual significant initial cost hurdle, rebates have an influence on purchase habits – to illustrate the point, rebates are tactics that are used frequently by marketers to influence consumers, get them to know new products and change their habits;

- In other jurisdictions, consumers like to rely on incentive programs to identify the most energy efficient option(s). Many consumers will trust the utility more than they would trust the vendors, and tend to integrate program eligibility criteria in their purchase/investment decision criteria; and

- Incentive programs increase the visibility and effectiveness of energy performance labeling program (informational program) like the Energy Star.

YUB-YECL-29

Reference: Residential Programs, Yukon Five Year Demand Side Management Plan

The Board wants to better understand the Residential programs proposed in the Five Year Demand Side Management Plan.

Request:

(a) With regard to the LED Lighting and Automotive Heater Timer Rebates, how much of the total costs of purchase will the rebates cover?

(b) With regard to the Low-cost Energy Efficient Products, please provide more details regarding what costs are included in the non-incentive and incentive costs? Please confirm whether or not rebates will be a part of this program. If confirmed, how much will rebates account for the total costs of these products?

(c) With regard to the Low-cost Energy Efficient Products, please confirm that YEC and YECL plan on promoting certain energy-efficient products in stores. Please describe whether YEC and YECL have started this initiative, and if so, identify in which stores.

(d) With regard to the CCHP and GSHP Initiative, please describe how much money YEC and YECL plan on giving to purchasers of a new home with a CCHP or GSHP system, or to owners of homes with electric central air heating systems to retrofit their home with CCHP or GSHP. For how much of the total costs will this incentive account?

(e) The Public Engagement, Education and Communication program appears to have a number of overlapping areas and activities with that of the Low-cost Energy Efficient Products program. Please confirm and explain the reasons for the overlaps.

(f) On page 20 of the Yukon Five Year Demand Side Management Plan, YEC and YECL noted that “many of the engagement initiatives carried out by the Utilities will also be used to disseminate information about the Yukon Housing conservation programs and the ESC energy conservation programs to increase value for the audience and create synergy between stakeholders.” Please

describe whether YEC and YECL will recover any of the costs attributable to these activities from these stakeholders. If not, how much money can be attributable to these activities?

Response:

(a) The incentive levels for this program are in the table below (taken from pages 72 and 76 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 67: Prescriptive List of Residential LED Lighting and Block-Heater Timer Energy Conservation Measures

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM151	Block Heater Timer	130 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$20.00/unit
ECM24	12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	110%	$44.00/unit	20.0 yr	$18.00/unit
ECM60	8W LED A19 Bulb	32.0 kWh/unit	0.011 kW/unit	110%	$30.00/unit	20.0 yr	$12.00/unit
ECM61	LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	110%	$20.00/unit	20.0 yr	$10.00/unit
ECM62	LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	110%	$51.00/unit	20.0 yr	$20.00/unit
ECM63	LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	110%	$43.00/unit	20.0 yr	$20.00/unit
ECM44	Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	80%	$25.00/unit	10.0 yr	$10.00/unit

Exhibit 1: Participation Projections – LED Lighting and Block-Heater Timer Rebates

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM151	Block Heater Timer	0 units	68 units	109 units	109 units	109 units	395 units
ECM24	12W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM60	8W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM61	LED MR16 Bulbs	55 units	259 units	259 units	259 units	259 units	1,089 units
ECM62	LED PAR30 Bulbs	14 units	79 units	79 units	79 units	79 units	328 units
ECM63	LED PAR38 Bulbs	10 units	59 units	59 units	59 units	59 units	246 units
ECM44	Spot or Task Lighting	9 units	41 units	41 units	41 units	41 units	172 units

(b) The plan is to have low-cost products being given away for free. This is one of the tactics for this program element. Rebate costs represent the full cost of the products (not the incremental cost).

Other tactics include educational materials, in-store events, sales people training, point-of-purchase materials. Therefore, the non-incentive costs include:

- Initial Set-up and Preparation of the distribution (Time);
- Procurement and Inventory Management (Time);
- Scorecard Crunching, Analysis & Reporting (Time);

- Expense Budget: Shipping (Mostly direct cost, perhaps some time);
- Point-of-Purchase Materials, and educational brochures - Early Support & Training, Research and Creation, In-store Events, Supervision (time); and
- Expense Budget Related with Materials (mostly direct costs).

This information is also provided in the detailed budget. Please refer to the *DSM Program Detailed Budgets*, provided as YUB-YECL-29(b) Attachment 1, for details.

(c) Yukon Energy and Yukon Electrical are planning on working with local retailers to implement this program; however, this program initiative has not started. Upon launch of the DSM programs, in-store promotion is identified as one of the communication strategies.

(d) As the CCHP and the GSHP programs are pilot programs, please refer to the incentive level chart and participant level projections as listed below (taken from pages 90 and 94 of the Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 81: Inputs and Assumptions of Residential New-Construction CCHP and GSHP Initiative

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM032	Pilot Cold Temp Heat Pumps	6,780 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$5,000.00/unit
ECM372	Pilot Ground Heat Pumps - Closed	8,605 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$9,000.00/unit
ECM03	Cold Temp Heat Pumps	6,780.0 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$2,500.00/unit
ECM37	Ground Heat Pumps - Closed	8,605.0 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$3,500.00/unit

Exhibit 84: Participation Projections – CCHP and GSHP Initiatives

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM032	Pilot Cold Temp Heat Pumps	1 units	0 units	0 units	1 units	0 units	2 units
ECM372	Pilot Ground Heat Pumps - Closed	0 units	1 units	1 units	0 units	0 units	2 units
ECM03	Cold Temp Heat Pumps	0 units	0 units	0 units	6 units	6 units	12 units
ECM37	Ground Heat Pumps - Closed	0 units	0 units	0 units	1 units	1 units	2 units

(e) It is standard practice to have elements of a DSM portfolio to complement each other and for their respective theory to be overlapping; together the program elements make a more effective portfolio. The division of the actual activities between one element or another, in this case, is arbitrary and is mostly based on the premise that the utilities are claiming a direct impact for the Low-cost Energy Efficient Products element and not for the Public Engagement, Education and Communication. However, the costs are not overlapping and there is no cost double-counting.

- Low-cost Energy Efficient Products element: was intended to induce change in purchase habits in retail stores therefore generating a direct impact which will be measureable through the monitoring of sales data. Please find details in the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

- Public Engagement, Education and Communication is a set of enabling tactics designed to boost uptake of all program elements (including the Low-Cost EE Products Elements) and to create a culture of energy efficiency. The utilities do not intend to claim a direct impact for this.

(f) Yukon Electrical and Yukon Energy have a cooperative relationship with Energy Solutions Centre (ESC) and Yukon Housing and will, through DSM public communication, assist in distributing additional energy efficiency materials that

are produced by these agencies. As these public communication activities are already part of the utility DSM programs there are no incremental costs associated with the distribution of additional ESC and Yukon Housing information. The benefit is purely an added convenience to the residential and commercial customer. Additionally as the utilities are mindful of the programming presented by ESC and Yukon Housing, there is an added benefit of uptake of the ESC and Yukon Housing programs.

Appendix C Detailed Budgets

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Lighting Redesign and Equipment Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings - ECM91	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions per Building	$ 315	$ 2,798	$ 5,639	$ 6,195	$ 4,786	$ 19,733
In-depth Blueprint & Layout Verification (1/3 verification)	$ 105	$ 933	$ 1,880	$ 2,065	$ 1,595	$ 6,578
Incentive Amount - Redesign Incentive - ECM91	$ 3,672	$ 20,350	$ 33,356	$ 33,356	$ 16,678	$ 107,412
Initial Set-up and Preparation	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 4,225	$ 10,964	$ 12,906	$ 13,294	$ 41,389
In-Depth Verification & Site Visit (1/3)	$ -	$ 1,408	$ 3,655	$ 4,302	$ 4,431	$ 13,796
Expense Budget Site Visits (1/3)	$ -	$ 282	$ 731	$ 860	$ 886	$ 2,759
Incentive for Typical Lighting Project in Existing Bldg - Office - ECM80	$ -	$ 1,873	$ 5,073	$ 5,797	$ 5,797	$ 18,541
Incentive for Typical Lighting Project in Existing Bldg - Food Retail - ECM81	$ -	$ 1,048	$ 2,768	$ 3,163	$ 3,163	$ 10,141
Incentive for Typical Lighting Project in Existing Bldg - Non Food Retail - ECM82	$ -	$ 4,402	$ 11,562	$ 13,213	$ 13,213	$ 42,390
Incentive for Typical Lighting Project in Existing Bldg - Hotel/Motel - ECM83	$ -	$ 2,120	$ 4,946	$ 5,652	$ 5,652	$ 18,370
Incentive for Typical Lighting Project in Existing Bldg - Restaurant - ECM86	$ -	$ 2,117	$ 4,939	$ 5,645	$ 5,645	$ 18,347
Incentive for Typical Lighting Project in Existing Bldg - Recreation - ECM87	$ -	$ -	$ -	$ -	$ -	$ -
Incentive for Typical Lighting Project in Existing Bldg - Warehouse - ECM88	$ -	$ 1,693	$ 3,950	$ 4,514	$ 4,514	$ 14,671
Incentive for 12W LED A19 Bulb Installed as Part of Projects - ECM92	$ -	$ 9,989	$ 23,309	$ 26,638	$ 26,638	$ 86,575
Incentive for 8W LED A19 Bulb Installed as Part of Projects - ECM93	$ -	$ 14,207	$ 33,150	$ 37,886	$ 37,886	$ 123,129
Incentive for LED MR16 Bulbs Installed as Part of Projects - ECM94	$ -	$ 9,249	$ 21,582	$ 24,665	$ 24,665	$ 80,162
Incentive for LED PAR30 Bulbs Installed as Part of Projects - ECM95	$ -	$ 14,799	$ 34,531	$ 39,464	$ 39,464	$ 128,259
Incentive for LED PAR38 Bulbs Installed as Part of Projects - ECM96	$ -	$ 10,763	$ 25,114	$ 28,701	$ 28,701	$ 93,280
Incentive for Spot or task lighting Installed as Part of Projects - ECM97	$ -	$ 3,700	$ 8,633	$ 9,866	$ 9,866	$ 32,065
Subtotal	$ 49,975	$ 105,956	$ 235,780	$ 264,892	$ 246,877	$ 903,480

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Lighting Redesign and Equipment Incentive - Government						
Number of Units - Total # of Buildings - ECM912	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions per Building	$ 168	$ 1,462	$ 2,913	$ 3,200	$ 2,472	$ 10,214
In-depth Blueprint & Layout Verification (1/3 verification)	$ 56	$ 487	$ 971	$ 1,067	$ 824	$ 3,405
Incentive Amount - Redesign Incentive - ECM912	$ 2,735	$ 14,216	$ 22,962	$ 22,962	$ 11,481	$ 74,356
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 2,227	$ 5,663	$ 6,666	$ 6,866	$ 21,423
In-Depth Verification & Site Visit (1/3)	$ -	$ 742	$ 1,888	$ 2,222	$ 2,289	$ 7,141
Expense Budget Site Visits (1/3)	$ -	$ 148	$ 378	$ 444	$ 458	$ 1,428
Incentive for Typical Lighting Project in Existing Bldg - Office - ECM802	$ -	$ 1,124	$ 3,044	$ 3,478	$ 3,478	$ 11,125
Incentive for Typical Lighting Project in Existing Bldg - Health - ECM842	$ -	$ 520	$ 1,213	$ 1,386	$ 1,386	$ 4,506
Incentive for Typical Lighting Project in Existing Bldg - Education - ECM852	$ -	$ 1,778	$ 4,148	$ 4,741	$ 4,741	$ 15,409
Incentive for Typical Lighting Project in Existing Bldg - Recreation - ECM872	$ -	$ 497	$ 1,161	$ 1,326	$ 1,326	$ 4,310
Incentive for Typical Lighting Project in Existing Bldg - Warehouse - ECM882	$ -	$ 339	$ 790	$ 903	$ 903	$ 2,934
Incentive for 12W LED A19 Bulb Installed as Part of Projects - ECM922	$ -	$ 3,227	$ 7,530	$ 8,606	$ 8,606	$ 27,970
Incentive for 8W LED A19 Bulb Installed as Part of Projects - ECM932	$ -	$ 4,590	$ 10,710	$ 12,240	$ 12,240	$ 39,780
Incentive for LED MR16 Bulbs Installed as Part of Projects - ECM942	$ -	$ 2,988	$ 6,973	$ 7,969	$ 7,969	$ 25,899
Incentive for LED PAR30 Bulbs Installed as Part of Projects - ECM952	$ -	$ 4,781	$ 11,156	$ 12,750	$ 12,750	$ 41,438
Incentive for LED PAR38 Bulbs Installed as Part of Projects - ECM962	$ -	$ 3,477	$ 8,114	$ 9,273	$ 9,273	$ 30,136
Incentive for Spot or task lighting Installed as Part of Projects - ECM972	$ -	$ 1,195	$ 2,789	$ 3,188	$ 3,188	$ 10,359
Subtotal	$ 2,959	$ 43,799	$ 92,402	$ 102,422	$ 90,250	$ 331,832
New Construction Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ 25,069	$ -	$ 48,010
Number of Units - Total # of Buildings	$ -	$ 272	$ 1,259	$ 2,017	$ 2,374	$ 5,922
Expense Budget Site Visits	$ -	$ 18	$ 84	$ 134	$ 158	$ 395
$ Equipment Incentive. Baseline-25% - ECM89	$ -	$ 2,989	$ 13,449	$ 20,920	$ 23,909	$ 61,266
$ Equipment Incentive. Baseline-40% - ECM90	$ -	$ 1,245	$ 5,604	$ 8,717	$ 9,962	$ 25,527
Subtotal	$ 22,942	$ 4,524	$ 20,395	$ 56,857	$ 36,403	$ 141,120

Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
New Construction Incentive - Government						
Number of Units - Total # of Buildings	$ -	$ 146	$ 678	$ 1,086	$ 1,278	$ 3,189
Expense Budget Site Visits	$ -	$ 10	$ 45	$ 72	$ 85	$ 213
$ Equipment Incentive. Baseline-25% - ECM892	$ -	$ 966	$ 4,345	$ 6,759	$ 7,724	$ 19,794
$ Equipment Incentive. Baseline-40% - ECM902	$ -	$ 402	$ 1,810	$ 2,816	$ 3,218	$ 8,247
Subtotal	$ -	$ 1,524	$ 6,878	$ 10,733	$ 12,307	$ 31,442
Energy Star Computer Incentive						
Initial Set-up and Preparation	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # Desktops and Laptops	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per 3 Units	$ 1,239	$ 8,085	$ 13,587	$ -	$ -	$ 22,911
Incentive for ENERGY STAR Desktop Computer and Monitor	$ 1,339	$ 8,477	$ 13,831	$ -	$ -	$ 23,647
Incentive for ENERGY STAR Laptop	$ 297	$ 1,884	$ 3,074	$ -	$ -	$ 5,255
Subtotal	$ 25,817	$ 18,446	$ 30,492	$ -	$ -	$ 74,754
Energy Star Computer Incentive - Government						
Number of Units - Total # Desktops and Laptops	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per 3 Units	$ 4,957	$ 32,339	$ 54,347	$ -	$ -	$ 91,643
Incentive for ENERGY STAR Desktop Computer and Monitor	$ 3,212	$ 20,345	$ 33,195	$ -	$ -	$ 56,753
Incentive for ENERGY STAR Laptop	$ 714	$ 4,521	$ 7,377	$ -	$ -	$ 12,612
Subtotal	$ 8,884	$ 57,206	$ 94,919	$ -	$ -	$ 161,008
High-Efficiency Refrigeration Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 45,654	$ 6,759	$ 41,547	$ 14,264	$ 108,224
Expense Budget Site Visits	$ -	$ 3,652	$ 541	$ 3,324	$ 1,141	$ 8,658
$ Equipment Incentive ECM98	$ -	$ -	$ 40,075	$ -	$ 40,075	$ 80,149
$ Equipment Incentive ECM98	$ -	$ -	$ 81,566	$ -	$ 81,566	$ 163,133
Subtotal	$ 22,942	$ 49,306	$ 128,941	$ 44,871	$ 137,047	$ 383,105

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
High-Efficiency Refrigeration Incentive - Government						
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 25,503	$ -	$ 27,056	$ -	$ 52,559
Expense Budget Site Visits	$ -	$ 2,040	$ -	$ 2,164	$ -	$ 4,205
$ Equipment Incentive ECM100	$ -	$ -	$ 9,904	$ -	$ 9,904	$ 19,808
Subtotal	$ -	$ 27,543	$ 9,904	$ 29,221	$ 9,904	$ 76,572
Engagement, Training and Communication						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 13,765	$ -	$ -	$ -	$ -	$ 13,765
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 4,591	$ 4,729	$ 4,871	$ 5,017	$ 19,209
Direct Engagement Workforce w/ Experienced Personnel	$ 65,280	$ 80,422	$ 70,614	$ 61,542	$ 63,389	$ 341,247
Expense budget - Communication, Trips, Materials	$ 24,000	$ 32,960	$ 33,949	$ 34,967	$ 36,016	$ 161,892
Expense Budget Trade Event	$ -	$ 25,750	$ 26,523	$ 27,318	$ 28,138	$ 107,728
Event Organization Related with the Trade Event	$ -	$ 22,957	$ 23,646	$ 24,355	$ 25,086	$ 96,044
Expense Budget Training	$ 16,000	$ 16,480	$ 16,974	$ -	$ -	$ 49,454
Event Organization - Training	$ 8,915	$ 9,183	$ 9,458	$ -	$ -	$ 27,557
Consulting Services to Deliver Training	$ 16,194	$ 16,680	$ 17,180	$ -	$ -	$ 50,054
Subtotal	$ 144,154	$ 209,024	$ 203,073	$ 153,054	$ 157,646	$ 866,951
Engagement, Training and Communication - Government (Marginal)						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 5,735	$ -	$ -	$ -	$ -	$ 5,735
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 1,148	$ 1,182	$ 1,218	$ 1,254	$ 4,802
Direct Engagement Workforce w/ Experienced Personnel	$ 17,920	$ 21,094	$ 16,295	$ 11,190	$ 11,525	$ 78,025
Expense budget - Communication, Trips, Materials	$ 6,000	$ 8,240	$ 8,487	$ 8,742	$ 9,004	$ 40,473
Subtotal	$ 29,655	$ 30,482	$ 25,965	$ 21,149	$ 21,784	$ 129,035
Program Management, Administration and Tracking						
Program Management	$ 64,000	$ 69,216	$ 67,898	$ 69,935	$ 72,033	$ 343,081
Tracking System Design, Then Servicing	$ 16,059	$ -	$ -	$ -	$ -	$ 16,059
Tracking System Maintenance	$ 892	$ 1,837	$ 1,892	$ 1,948	$ 2,007	$ 8,575
Feed tracking system and reporting	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Third-party M&V	$ -	$ 77,250	$ -	$ -	$ 140,689	$ 217,939
Subtotal	$ 87,637	$ 157,485	$ 79,248	$ 81,625	$ 224,762	$ 630,758
TOTAL	$ 394,965	$ 705,294	$ 927,996	$ 764,824	$ 936,980	$ 3,730,059

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Residential DSM Program Design - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
LED Lighting and Automotive Heater Timer Rebates						
Build Transactional and Operational Infrastructure	$ 11,471	$ -	$ -	$ -	$ -	$ 11,471
Number of Units Automotive Heater Timers - ECM151	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions - ECM151 (1 unit/transaction)	$ -	$ 1,407	$ 2,309	$ 2,378	$ 2,449	$ 8,543
$ Equipment Incentive. ECM151	$ -	$ 1,366	$ 2,176	$ 2,176	$ 2,176	$ 7,894
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - 12W LED A19 Bulbs - ECM24	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - 8W LED A19 Bulb - ECM60	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED MR16 Bulbs - ECM61	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED PAR30 Bulbs - ECM62	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED PAR38 Bulbs - ECM63	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - Spot or Task Lighting - ECM44	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions (5 units per transaction)	$ 3,136	$ 13,787	$ 14,201	$ 14,627	$ 15,065	$ 60,816
Phone verification (1/20 spot check)	$ 874	$ 3,841	$ 3,956	$ 4,075	$ 4,197	$ 16,944
Site visit (1/100 verification)	$ 699	$ 3,073	$ 3,165	$ 3,260	$ 3,358	$ 13,555
Expense Budget Site Visits	$ 314	$ 1,379	$ 1,420	$ 1,463	$ 1,507	$ 6,082
Update the incentive list (once per year)	$ -	$ 2,296	$ 2,365	$ 2,436	$ 2,509	$ 9,604
Incentive Amount - 12W LED A19 Bulbs - ECM24	$ 6,276	$ 26,183	$ 26,183	$ 26,183	$ 26,183	$ 111,008
Incentive Amount - 8W LED A19 Bulb - ECM60	$ 4,184	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 74,005
Incentive Amount - LED MR16 Bulbs - ECM61	$ 547	$ 2,586	$ 2,586	$ 2,586	$ 2,586	$ 10,891
Incentive Amount - LED PAR30 Bulbs - ECM62	$ 272	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 6,567
Incentive Amount - LED PAR38 Bulbs - ECM63	$ 198	$ 1,181	$ 1,181	$ 1,181	$ 1,181	$ 4,921
Incentive Amount - Spot or Task Lighting - ECM44	$ 87	$ 408	$ 408	$ 408	$ 408	$ 1,717
Subtotal	$ 50,998	$ 76,535	$ 78,978	$ 79,801	$ 80,648	$ 366,960

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Low-Cost Energy Efficient Products						
Initial Set-up and Preparation	$ 17,206	$ -	$ -	$ -	$ -	$ 17,206
Low-cost EE P. - Procurement and Inventory Management	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Low-cost EE P. - Scorecard Crunching, Analysis & Reporting	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Expense Budget: Shipping	$ 6,000	$ 8,240	$ 8,487	$ 8,742	$ 9,004	$ 40,473
Cost of Giveaways - Pilot 12W LED A19 Bulbs - ECM242	$ 2,640	$ 2,640	$ 2,640	$ 2,640	$ 2,640	$ 13,200
Cost of Giveaways - Pilot 8W LED A19 Bulb - ECM602	$ 1,860	$ 1,860	$ 1,860	$ 1,860	$ 1,860	$ 9,300
Cost of Giveaways - Pilot LED MR16 Bulbs - ECM612	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
Cost of Giveaways - Pilot LED PAR30 Bulbs - ECM622	$ 1,920	$ 1,920	$ 1,920	$ 1,920	$ 1,920	$ 9,600
Cost of Giveaways - Pilot LED PAR38 Bulbs - ECM632	$ 1,060	$ 1,060	$ 1,060	$ 1,060	$ 1,060	$ 5,300
Cost of Giveaways - Pilot Spot or Task Lighting - ECM442	$ 150	$ 150	$ 150	$ 150	$ 150	$ 750
Cost of Giveaways - Pilot Ultra Low-flow Showerheads - ECM092	$ 480	$ 640	$ 480	$ 320	$ 320	$ 2,241
Cost of Giveaways - Pilot Power Bars for PCs and TVs - ECM112	$ 3,000	$ 3,000	$ 2,000	$ 2,000	$ 1,500	$ 11,500
Cost of Giveaways - Pilot DHW Tank Insulation - ECM182	$ 1,503	$ 2,255	$ 2,255	$ 1,503	$ 1,503	$ 9,019
Cost of Giveaways - Pilot DHW Pipe Insulation - ECM202	$ 32	$ 47	$ 47	$ 32	$ 32	$ 190
Cost of Giveaways - Pilot Motion Detectors - Indoor and Outdoor -	$ 1,376	$ 1,376	$ 918	$ 918	$ 688	$ 5,276
Cost of Giveaways - Pilot Auto Heater Timers - ECM152	$ 1,125	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 10,125
Cost of Giveaways - Pilot Prog. Thermostats (Central) - ECM142	$ 625	$ 1,250	$ 938	$ 625	$ 625	$ 4,063
Cost of Giveaways - Pilot Prog. Thermostats - ECM212	$ 14,271	$ 25,689	$ 22,834	$ 17,126	$ 11,417	$ 91,338
Cost of Giveaways - Pilot E-Star TVs - ECM062	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 11,250
Cost of Giveaways - Pilot E-Star Printers and Fax - ECM082	$ 800	$ 800	$ 800	$ 800	$ 800	$ 4,000
Research and Creation of Materials - Early Support & Training	$ 17,206	$ -	$ -	$ -	$ -	$ 17,206
Research and Creation of Materials - Bulk of the Work	$ 23,040	$ 31,642	$ 32,591	$ 33,569	$ 34,576	$ 155,417
Research and Creation of Materials - Supervision	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Expense Budget Related with Materials	$ 30,000	$ 41,200	$ 42,436	$ 43,709	$ -	$ 157,345
Subtotal	$ 147,605	$ 156,818	$ 155,291	$ 151,699	$ 103,698	$ 715,111

Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Residential DSM Program Design - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
New-construction CCHP and GSHP Initiative						
Coordination of the Pilot Projects (3-elem. DHW, CCHP, GSHP)	$ 8,915	$ 18,366	$ 18,917	$ -	$ -	$ 46,198
Heavy incentive - Pilot CCHP ECM032	$ 5,000	$ -	$ -	$ 5,000	$ -	$ 10,000
Heavy incentive - Pilot GSHP ECM372	$ -	$ 9,000	$ 9,000	$ -	$ -	$ 18,000
Project-level M&V of Pilot Projects: % of Project Costs	$ -	$ 3,600	$ 3,600	$ -	$ -	$ 7,200
Build Transactional and Operational Infrastructure	$ -	$ -	$ -	$ 25,069	$ -	$ 25,069
Process Transactions CCHP - ECM03	$ -	$ -	$ -	$ 5,245	$ 5,402	$ 10,648
Process Transactions GSHP - ECM37	$ -	$ -	$ -	$ 874	$ 900	$ 1,775
Expense Budget Site Visits	$ -	$ -	$ -	$ 1,530	$ 1,576	$ 3,106
$ Equipment Incentive. CCHP - ECM03	$ -	$ -	$ -	$ 15,000	$ 15,000	$ 30,000
$ Equipment Incentive. GSHP - ECM37	$ -	$ -	$ -	$ 3,500	$ 3,500	$ 7,000
Subtotal	$ 13,915	$ 30,966	$ 31,517	$ 56,218	$ 26,379	$ 158,994
Engagement, Education and Communication						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Direct Engagement Workforce w/ Junior Personnel	$ 53,760	$ 73,830	$ 76,045	$ 78,327	$ 80,676	$ 362,639
Direct Engagement Workforce w/ Experienced Personnel	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 5,739	$ 5,911	$ 6,089	$ 6,271	$ 24,011
Expense budget - Communication, Trips, Materials	$ 30,000	$ 41,200	$ 42,436	$ 43,709	$ 45,020	$ 202,365
Subtotal	$ 113,388	$ 129,953	$ 133,851	$ 137,867	$ 142,003	$ 657,061
Program Management, Administration and Tracking						
Program Management	$ 83,200	$ 59,328	$ 54,318	$ 55,948	$ 57,626	$ 310,420
Tracking System Design, Then Servicing	$ 11,471	$ 3,544	$ -	$ 7,521	$ 7,746	$ 30,282
Tracking System Maintenance	$ 892	$ 1,837	$ 1,892	$ 1,948	$ 2,007	$ 8,575
Feed tracking system and reporting	$ 8,024	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 46,442
Third-party EM&V	$ -	$ 66,950	$ -	$ -	$ 112,551	$ 179,501
Subtotal	$ 103,586	$ 140,842	$ 65,668	$ 75,159	$ 189,964	$ 575,220
TOTAL	$ 429,492	$ 535,113	$ 465,305	$ 500,743	$ 542,692	$ 2,473,346

YUB-YECL-30

Reference: General Service Programs, Yukon Five Year Demand Side Management Plan, page 20

The Board wants to better understand the General Service programs proposed in the Five Year Demand Side Management Plan.

Request:

(a) With regard to the Lighting Redesign and Equipment Incentive, how much of the total costs of these retrofits will the rebates cover?

(b) With regard to the High Efficiency Refrigeration Incentive, how much of the total costs of these retrofits will the rebates cover?

(c) On page 22 of the DSM plan, YEC and YECL noted that they "will provide extensive refrigeration-specific technical assistance to identify the opportunities, to develop the projects, to manage the construction works, and to measure and monitor the performance of the projects." Please explain how or when YEC and YECL developed the technical expertise in refrigeration specifics.

(d) With regard to the Energy Star Computer Incentive, how much of the total costs of these products will the rebates cover? Are any Yukon-based companies or organizations eligible for this program?

(e) With regard to the New Construction Incentive, how much of the total costs of these buildings will the rebates cover? Are any Yukon-based companies or organizations eligible for this program?

Response:

(a) The Lighting Redesign and Equipment Program is based on an incentive level for a dollar per square foot with a cap. This program also includes an added prescriptive incentive for the installation of LED fixtures and lights, which is also based on a dollar amount per unit and is consistent with the residential LED program. The total incentive amount for this program are as follows (taken from page 33 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 20: Budget – Lighting Redesign and Equipment Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$4	$96	$213	$239	$222	$773
Non-Incentive:	$72	$56	$46	$50	$91	$314
Total:	$76	$152	$259	$289	$312	$1,087

Exhibit 11: Budget – Lighting Redesign and Equipment Incentive including Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$6	$135	$294	$327	$299	$1,062
Non-Incentive:	$81	$77	$66	$72	$127	$425
Total:	$88	$213	$360	$400	$427	$1,487

(b) The High Efficiency Refrigeration Program is based on an incentive level for a dollar per kilowatt hour rate, based on annual savings. The total incentive amount for this program are as follows taken *(*from page 42 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 23: Budget – High Efficiency Refrigeration Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$0	$122	$0	$122	$243
Non-Incentive:	$34	$69	$17	$55	$43	$218
Total:	$34	$69	$139	$55	$165	$461

Exhibit 34: Budget – High Efficiency Refrigeration Incentive including Government Buildings

$1,000s						
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$0	$132	$0	$132	$263
Non-Incentive:	$36	$100	$19	$86	$49	$290
Total:	$36	$100	$151	$86	$180	$553

(c) Given the relatively small number of potential participants, energy engineers will be engaged by the utilities to build tailor-made technical assistance packages for each participant. These packages may include an initial walk-through audit, an investment grade audit, procurement support, project management and/or project performance measurement and verification. The technical assistance budget will be commensurate with the estimated savings.

(d) All Yukon Electrical and Yukon Energy general service account holders will be eligible for the Energy Star Computer incentive. Eligibility for government general service accounts will be determined based on the YUB decision on the inclusion of government accounts. The incentive level is fixed, the product cost is variable. This allows for participants to choose the most appropriate product for their application (taken from page 45 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 39: Prescriptive List of ENERGY STAR Computer Conservation Measures for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM101	ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	95%	$0.00/unit	4.0 yr	$30.00/unit
ECM102	ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	95%	$0.00/unit	4.0 yr	$10.00/unit

Exhibit 40: Prescriptive List of ENERGY STAR Computer Conservation Measures for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM1012	Gov. ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	55%	$0.00/unit	4.0 yr	$18.00/unit
ECM1022	Gov. ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	55%	$0.00/unit	4.0 yr	$6.00/unit

(e) All Yukon Energy and Yukon Electrical general service account holders will be eligible for the New Construction Incentive. Eligibility for government general service accounts will be determined based on the YUB decision on the inclusion of government accounts. The incentive will be determined using a dollar per square foot rate if the building complies with a certain standard. The standard will be designed to be slightly more stringent than model national energy building code minus 25 percent and the City of Whitehorse's building and plumbing bylaw. The total incentive amount for this program are as follows (taken from page 57 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 58: Budget – Electricity-Efficient New Construction Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$4	$19	$30	$34	$87
Non-Incentive:	$27	$7	$5	$31	$13	$83
Total:	$27	$12	$24	$61	$47	$170

Exhibit 59: Budget – Electricity-Efficient New Construction Incentive including Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$6	$25	$39	$45	$115
Non-Incentive:	$28	$9	$6	$33	$16	$93
Total:	$28	$15	$32	$72	$61	$208

YUB-YECL-31

Reference: Business risk, YECL Application, Section 8-Return on Rate Base, Page 8-4, Lines 13-15

Consistent with the various business risk factors identified in its 2008-2009 GRA, Yukon Electrical's ongoing business risks encompass market demand, operational costs, physical hazards and regulation."

The Board wants to understand how the business risks identified in the quote have changed since the 2008-2009 GRA

Request:

(a) Is it the position of YECL that it faces greater business risks than it did in the 2008-09 GRA? If yes, explain why.

(b) Please discuss how the following risks have changed since the 2008-09 GRA:

i. Market demand

ii. Operational costs

iii. Physical hazards

iv. Regulation

(c) For each of the above risk factors, please quantify the impact of the change in risk.

Response:

(a - c) At the outset, it should be noted that Yukon Electrical's request for an increased common equity ratio arises primarily from the recognition in other jurisdictions that similar increases have been approved for other utilities which has Yukon Electrical has been compared or benchmarked against. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased

from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Even in the absence of increased business risk, Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

Further to the above, it is Yukon Electrical's position its business risks for this Application remain largely consistent with those assessed in 2008 as part of its 2008-2009 GRA. At that point in time, Yukon Electrical's expert witness concluded that Yukon Electrical's business risks were higher than those of the typical Canadian electricity distribution utility and higher than average within the spectrum of Canadian utilities. Further to this position, however, Yukon Electrical notes the following areas where its business risks have increased modestly since 2008.

Market Demand:

Market demand risk relates to those factors that can lead to annual volatility in electricity sales and loss of customers. Between 2008 and 2012, Whitehorse residential annual use per customer has increased from 10,489 kWh in 2008 to 11,128 kWh (Normalized 2012 Actual). This increase appears to be, in large part, due to a resurgence of electric space heating in the Whitehorse area. While Yukon Electrical has incorporated this increase into its 2013-2015 sales forecast, there is now added risk of this space heating electrical load shifting to home heating fuel, propane or wood. Homes that are supplementing fuel heating with portable electric space heaters can choose to not do so. For purposes of quantification, this 639 kWh change in UPC impacted Yukon Electrical's 2013 sales revenue forecast by approximately $850,000 (639 X 10,792 X .1237).

Since 2008, approximately 2,500,000 kWh of secondary sales electric load (related to heating and processing) has been converted into primary load. This new primary load has been incorporated into Yukon Electrical's primary sales forecast for 2013-2015 and annually represents approximately $400,000 of Yukon Electrical's commercial sales revenue forecast. Given that this load is

convertible to a fossil fuel solution, there is now increased risk to Yukon Electrical of decreased primary sales due to fuel switching.

As part of this GRA, Yukon Electrical and Yukon Energy are jointly proposing a Demand Side Management (DSM) program. This program, which was not in place in 2008, will increase emphasis on energy efficiency and conservation. While Yukon Electrical has incorporated the forecast impact of the program into its forecast (please refer to WL-YECL-8(a)), overall sales forecast risk has increased as a result of the introduction of the program. Should the program be more successful than anticipated, it will reduce Yukon Electrical's actual sales as compared to forecast.

In its 2008-2009 GRA, Yukon Electrical did not forecast any sales to industrial customers. In this Application, Yukon Electrical is forecasting industrial sales to one customer, Whitehorse Copper Tailing (WHCT). As it continues to be unclear as to whether or not and when this customer may connect and what the ultimate amount of load will be, Yukon Electrical has requested a deferral account that will address any additional earnings or decreases in earnings as a result of the actual load being higher or lower than forecast. Assuming this deferral is approved by the Board, there is no change in market demand risk related to industrial sales in this Application as compared to the 2008-2009 GRA.

Operational Costs:

As detailed in the following table, Yukon Electrical is forecasts a shift in the mix of its assets towards generation during the test period. The presence of generation assets in rate base generally increases the Yukon Electrical's business risk relative to a pure distribution utility, as the operational risks associated with generation exceed those of distribution "wires" operations.

	Actual		GRA		
	2008	**2012**	**2013**	**2014**	**2015**
Generation	14%	13%	16%	18%	19%
Distribution	79%	81%	77%	75%	74%
Other	7%	6%	7%	7%	7%
Total	100%	100%	100%	100%	100%

Since the 2008-2009 GRA, Yukon Electrical has obtained a 25-year water licence for operation of the Fish Lake Hydro System which stipulates additional monitoring, reporting and operational requirements as compared to the previous licence. Please refer to YUB-YECL-53 (to be filed August 29) for an overview of the new requirements associated with this licence. This change has increased Yukon Electrical's operational risk with respect to hydro generation at the Fish Lake hydro plant.

Yukon Electrical, as part of this Application, is also proposing its Watson Lake Bi-Fuel Project whereby it will be possible to fuel the generators in Watson Lake with both diesel fuel and natural gas. This project is subject to new permitting and oil and gas regulations that Yukon Electrical must follow in order to provide service to its customers. The project offers customers benefits related to emissions reduction, fuel cost savings and diversity. The project is, however, a first of its kind project in the north and the steps necessary to achieve approvals are significant and contain a level of uncertainty. The Watson Lake Bi-Fuel Project will increase Yukon Electrical's operational risk as compared to 2008.

YUB-YECL-32

Reference: Return on equity, YECL Application, Schedule 8.1

The Board wants to confirm the return on equity for 2008 to 2012.

Request:

(a) Please confirm the following returns from Schedule 8.1:

(i) 2008: 7.03%
(ii) 2009: 11.35%
(iii) 2010: 10.54%
(iv) 2011: 10.74%
(v) 2012: 10.18%

(b) Please confirm that the average ROE for the years 2008 to 2012 was 9.968%.

(c) Please discuss the need for an increase in approved ROE to 9.21%, given that YECL has been earning an average of 9.68% when the approved ROEs in the past five years were lower than the requested ROE.

Response:

(a) Confirmed.

(b) Yukon Electrical confirms its average ROE for the years 2008 to 2012 was 9.968%. The BCUC GCOC Benchmark average for the same period, including the awarded 0.46% risk premium, was 9.68%[1].

(c) As detailed throughout this Application, Yukon Electrical is experiencing significant cost pressures and capital requirements that require it to come forward to the Board to ensure that it has an opportunity to continue to provide safe and reliable service to its customers while affording the company an opportunity to earn a fair return for the test period 2013-2015.

[1] Average BCUC Benchmark for the period 2008-2012 was 9.22%: 2008 (8.62%); 2009 (8.99% (8.47% + 9.50% (effective July 1, 2009)); 2010 (9.50%); 2011 (9.50%); 2012 (9.50%).

The requested ROE of 9.21% is linked to the recently approved BCUC GCOC benchmark rate of 8.75% plus a risk premium of 0.46%. As stated in Decision 2009-2, the Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

YUB-YECL-33

Reference: Common equity ratio, YECL Application, Section 8 – Return on Rate Base, page 8-6

Yukon Electrical is requesting to increase its common equity ratio from the current level of 40% to 44% for each of 2013, 2014 and 2015.

Although the BCUC increased its common equity ratio for its benchmark utility after 2008, it also lowered the common equity ratio effective January 1, 2013.

Request:

(a) Please confirm that the BCUC reduced the common equity ratio for its benchmark utility from 40% to 38.5% in Order G-75-13.

(b) Given that the BCUC has determined that a lower common equity ratio is appropriate from 2013, please discuss the differences for YECL which make an increase of 4% to its common equity ratio more reasonable than the benchmark utility for BCUC.

Response:

(a) Yukon Electrical confirms the following changes with respect to the BCUC common equity ratio for its benchmark utility have taken place since the Yukon Utilities Board Decision 2009-2 (February 12, 2009):

Common equity ratio as of February 12, 2009:	35.0%[1]
Common equity ratio effective January 1, 2010:	40.0%[2]
Common equity ratio effective January 1, 2013:	38.5%[3]

(b) Yukon Electrical's request for a 9.21% ROE and a common equity ratio of 44% is based on the expert evidence it filed in its 2008-2009 GRA that concluded Yukon Electrical's business risks are: (1) higher than those of the typical

[1] Per BCUC Order G-14-06 dated March 2, 2006, that stated the appropriate common equity component allowed in the capital structure for the benchmark utility, Terasen Gas Inc. (TGI) is 35%. This Order also addressed the appropriate common equity component allowed in the capital structure of Terasen Gas (Vancouver Island) (TGVI) which was set at 40%.
[2] Per BCUC Order G-158-09 dated December 16, 2009.
[3] Per BCUC Order G-75-13 dated May 10, 2013.

Canadian distribution utility; (2) higher than average within the spectrum of Canadian utilities; and (3) that the capital structure for Yukon Electrical should respect the stand-alone principle. Please refer to YUB-YECL-33(b) Attachment 1 for a copy of the expert evidence filed in the 2008-2009 GRA. As detailed in YUB-YECL-31, it is Yukon Electrical's position that its business risk has increased modestly since 2008.

Regardless of Yukon Electrical's assessment that its business risk has increased modestly since 2008, regulatory decisions and processes in British Columbia and the Northwest Territories have occurred since 2008 that support Yukon Electrical's requests in this Application.

Firstly, in British Columbia, the BCUC has reaffirmed the long history and importance of the stand-alone principle in Canadian utility regulation as part of its BCUC Generic Cost of Capital Proceeding (Stage 1) Decision May 10, 2013 (page 100). As detailed in this Application, Stage 1 of this proceeding has now concluded with Order G-75-13 stating the benchmark utility, FortisBC Energy Inc. (FEI), is to have an ROE of 8.75% and a common equity ratio of 38.5% for the years 2013-2015 subject to any adjustments in 2014 or 2015 as a result of the Automatic Adjustment Mechanism (AAM).

Now that Stage 1 has been completed in British Columbia, Stage 2, dealing with business risks of non-benchmark utilities, has begun. A summary of the requested ROEs and common equity ratios in that proceeding is as follows:

	ROE	Equity Ratio
FortisBC Inc. (Electricity)	9.25%-9.50%	40%
FortisBC Energy (Vancouver Island)	9.25%	43.50%
FortisBC Energy (Whistler)	9.50%	45%
Pacific Northern Gas Ltd.	9.75%	50%
Pacific Northern Gas (N.E.) Ltd.	9.50%	45%

Further to the situation in British Columbia, the Northwest Territories Public Utilities Board approved common equity ratios for Northland Utilities (Yellowknife) and Northland Utilities (NWT) of 43.5% and 44%, respectively, for the test years 2008-2010 as well as 2011-2013. As stated in Yukon Electrical's 2008-2009 expert evidence, Yukon Electrical shares similar business risks with Northland Utilities (Yellowknife).

For purposes of this Application, it is Yukon Electrical's position that its ROE and capital structure should be based on its evidence that (i) its business risks are higher than the typical distribution utility; and (ii) applicability of the stand-alone principle in the Yukon.

In order to provide perspective on the various companies that are involved in the Stage 2 process in British Columbia as well as the Northland companies that share similar risks to Yukon Electrical, please refer to the following table that is based on information obtained from the BCUC Stage 2 process as well as Northland's 2012 statistics:

	FortisBC Energy Inc. (BCUC Benchmark)	Yukon Electrical	FortisBC Inc.	FortisBC Energy (Vancouver Island)	FortisBC Energy (Whistler)	Pacific Northern Gas Ltd.	Pacific Northern Gas (N.E.) Ltd.	Northland Utilities (Yellowknife)	Northland Utilities (NWT)
Type of Utility	Gas Distribution Company	Electric Distribution & Generation Company	Electric Generation, Transmission and Distribution	Gas Distribution Company	Gas Distribution Company	Gas Transmision & Distribution Company	Gas Distribution Company	Electric Distribution Company	Electric Generation, Transmission & Distribution Company
Service Area	Lower Mainland, Inland, Columbia and Revelstoke (propane)	Whitehorse and area, Watson Lake and area, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Old Crow, Beaver Creek, Destruction Bay, Burwash Landing and Swift River	South Central Interior of British Columbia	Vancouver Island, Sunshine Coast, and Powell River	Whistler	West Central portion of British Columbia from Summit River to west coast	Northwest British Columbia Fort St. John / Dawson Creek areas	Yellowknife and N'Dilo	Hay River, Trout Lake, Wekweeti, Kakisa, Dory Point, Fort Providence and the Katio'odeeche First Nation
Common Equity Ratio for 2013 - (1) Approved or (2) Applied For	38.5% (1)	44% (2)	40% (2)	43.5% (2)	45% (2)	50% (2)	45% (2)	43.5% (1)	44% (1)
ROE for 2013 (1) Approved or (2) Applied For	8.75% (1)	9.21% (2)	9.25%-9.50% (2)	9.25% (2)	9.5% (2)	9.75% (2)	9.5% (2)	9.3%(1)	9.3% (1)
2012 Rate Base ($ millions)	$2,692.8	$60.0	$1,088.5	$778.7	$41.7	$127.9	$45.0	$40.7	$15.2
2012 Sales/Transportation Volumes	178,735 TJs	316 GWh	3,144 GWh	38,083 TJs	686 TJs	4,053 Tjs	5,422 Tjs	159 GWh	35 GWh
2012 Number of Customers	893,040	16,702	113,915	101,098	2,612	20,496	19,379	8,140	2,718

It is Yukon Electrical's position, based on its previously filed business risk expert evidence in 2008-2009 GRA and as updated by Yukon Electrical management in in YUB-YECL-31, its overall business risk is more aligned with the referenced smaller distribution utilities in British Columbia and the Northwest Territories as opposed to the British Columbia gas and electric utilities with billion dollar rate bases. For these reasons, as well as reference to the stand-alone principle, the requested 9.21% ROE and common equity ratio of 44% are reasonable for purposes of this Application.

Yukon Electrical Company Limited

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
April 2008

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of, and a senior consultant with, Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, oil and gas pipelines, and telephone companies in more than 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Yukon Electrical Company Limited ("Yukon Electrical") has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity (ROE) for the Company's 2008 and 2009 test years, using, for the express purpose of these two test years, the benchmark return on equity established by the Alberta Energy and Utilities Board (EUB)[1] as a point of departure.

In that context, I have estimated the capital structure that would fully reflect the business risks of Yukon Electrical. Based on my analysis, the common equity ratio that would fully compensate for the business risks of Yukon Electrical lies at the upper end of a range of 47.5% to 52.5%.

At a common equity ratio of 52.5%, the allowed return on equity for Yukon Electrical should be equal to that applicable to an average risk Canadian utility, that is, a benchmark return on equity. For the express purpose of this proceeding, I recommend adopting the benchmark return on equity derived in the EUB's Generic Cost of Capital Decision 2004-052 (July 2, 2004), as adjusted for changes in interest rates. The benchmark return on

[1] Now the Alberta Utilities Commission or "AUC".

equity adopted by the EUB under its generic cost of capital automatic adjustment mechanism for 2008 was 8.75%, based on a long-term Canada bond yield of 4.55%.

With respect to the benchmark return on equity for test years 2008-2009, I recommend that the Yukon Utilities Board ("the Board"):

1. Adopt a single return on equity for both test years, based on the forecast average long-term Government of Canada bond yield of 4.5%; and,

2. Apply the EUB's automatic adjustment formula to arrive at a benchmark ROE for 2008-2009.

Since the forecast average long-term Government of Canada bond yield for 2008-2009, at 4.5%, is virtually identical to the forecast relied on by the EUB to determine the allowed ROE for 2008, the application of the automatic adjustment formula produces a benchmark return on equity of approximately 8.75% for 2008-2009. The indicated benchmark return on equity of 8.75% would be applicable to Yukon Electrical at a common equity ratio of 52.5%.

However, the benchmark ROE is viewed as below the level consistent with a fair and reasonable return. Thus, requiring shareholders to commit additional equity to achieve a 52.5% equity ratio to have the opportunity to earn a benchmark equity return regarded as too low is fundamentally incongruous. As a result, I recommend that the actual common equity ratio of Yukon Electrical be raised to 47.5% and to allow an incremental equity risk premium of 0.50% above the benchmark return on equity. The 0.50% incremental equity risk premium compensates for the difference in financial risk between the proposed 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a common equity ratio of 47.5%, the allowed ROE for Yukon Electrical should be set at 9.25%.

II. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN COST OF CAPITAL AND CAPITAL STRUCTURE

The cost of capital is largely a function of business risk, that is, the risks arising from the operations/assets of a firm. The cost of capital, however, is also a function of financial risk, i.e., additional risk borne by the common equity shareholder because the firm is using fixed obligation securities (e.g., long-term debt) to finance a portion of its assets. Therefore, the capital structure, comprised of fixed obligation securities and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used.

However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will accompany an increase in the cost of equity.

B. APPROACHES TO DETERMINING THE FAIR RETURN

Recognizing the relationship between the cost of capital and capital structure, there are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or benchmark. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an

adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines.[2] It is also the approach that was adopted by the EUB in its Generic Cost of Capital Decision. In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/EUB approach as long as the combination of actual/allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark return on equity. The combination of capital structures and equity risk premiums has also been used in Ontario and Québec.

For purposes of this proceeding, I have utilized the first approach and estimated the capital structure that is intended to fully reflect the business risks of Yukon Electrical. In other words, I have estimated a capital structure for Yukon Electrical, based on the principles set out in Section III that would be compatible with the application of a benchmark return on equity to Yukon Electrical. If, however, the common equity ratio

[2] In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002, 36% in 2005 and 40% in 2007.

adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

C. BENCHMARK RETURN ON EQUITY

1. Conceptual Considerations

Both approaches to determining a fair return outlined in Section II.B rely on the measurement of the equity return that would be applicable to a benchmark utility or average risk Canadian utility. That return will be referred to as a benchmark return on equity. A capital structure for Yukon Electrical would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return on equity; and (c) would equate the level of total (business and financial) risk faced by Yukon Electrical to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the common equity ratio for Yukon Electrical is established so that no adjustment to the benchmark return on equity is required.[3]

The term benchmark utility is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the benchmark utility reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve a particular debt rating,

[3] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." (Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999)

typically an A rating. The typical, average risk Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's (S&P).

Designation of a debt rating as an indicator of relative risk recognizes that (a) debt ratings reflect both business and financial risk, and (b) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would require lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return on equity.

For specific purposes of this proceeding, I recommend adopting as the benchmark return on equity, the generic return on equity applicable to the Alberta utilities as adjusted for any forecast changes in interest rates. The return on equity adopted by the EUB for 2008 was 8.75%, based on a forecast long-term Canada bond yield of 4.55%.[4]

2. Benchmark Return on Equity for Test Years 2008-2009

Expert testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Preparation of testimony, responses to information requests and cross-examination of witnesses entail a considerable amount of money, time and effort. As a result, the cost impact on a utility the size of Yukon Electrical can be

[4] Order 2007-0347, November 30, 2007.

significant. Yukon Electrical is proposing that for the specific purposes of this proceeding, the Alberta generic return on equity be used as a point of departure for establishing its allowed return on equity for the 2008-2009 test years, as adjusted for changes in interest rates. The generic return on equity established by the EUB in Decision 2004-052 and adjusted automatically each year in subsequent Orders is virtually identical to "benchmark" ROEs adopted by other Canadian regulators, including the National Energy Board and, implicitly, by the Public Utilities Board of the Northwest Territories when it established the allowed ROE for Northwest Territories Power Corporation in Decision 13-2007 (August 29, 2007). Using the EUB's generic return on equity as a point of departure, the costs associated with the determination of the allowed return on equity for Yukon Electrical should be greatly reduced. The cost of capital testimony can then focus on the issue of the capital structure that is required to fully compensate for the utility's business risks and, if necessary, given the specific financing considerations of the utility, any incremental equity risk premium relative to the benchmark return on equity that is required.

Given these considerations, I accept, for the express purposes of this proceeding, that the return on equity determined by the EUB in Decision 2004-052, as adjusted for changes in interest rates since the decision was issued, will be used as the basis for establishing the allowed return on equity for Yukon Electrical.[5] That return on equity, however, can only be applied to a common equity ratio that fully compensates for Yukon Electrical's business risks.

Decision 2004-052 established an automatic adjustment mechanism for determining a utility's allowed return on equity in response to a change in interest rates. Automatic adjustment mechanisms for determining a utility's allowed return on equity are relied

[5] In my opinion, as well as that of Yukon Electrical, the EUB benchmark return on equity is below the level commensurate with the comparable returns standard. The EUB as well as the NEB have initiated proceedings to determine whether their automatic adjustment mechanisms continue to produce a fair return. In the ATCO Utilities' view (with which I concur), as filed with the AUC on April 4, 2008, the automatic adjustment mechanism does not produce a fair return. Nevertheless, until such time as the issue has been reviewed by the AUC, Yukon Electrical is prepared to accept the EUB "benchmark" as a point of departure for establishing its allowed ROE for 2008 and 2009.

upon in six regulatory jurisdictions in Canada. The various mechanisms are all quite similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a base, or initial, return on equity and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base allowed return on equity are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula, or adjustment factor, to be used to adjust the allowed return on equity from one year to the next. The forecast yield on the long-term Government of Canada bond is used as the proxy for the risk-free rate.

Application of an adjustment mechanism like those used in most Canadian jurisdictions requires the following steps:

Step 1: Establish the forecast long-term Canada bond yield for the test year(s),

Step 2: Apply the adjustment factor to the difference between the test year forecast(s) of the long-term Canada bond yield and the bond yield underlying the base allowed return on equity, and

Step 3: Adjust the base allowed return on equity by the amount(s) determined in Step 2.

In five of the six Canadian jurisdictions that currently use an automatic adjustment mechanism,[6] the adjustment factor is set at 0.75, i.e., the change in allowed return on equity equals 75% of the change in the forecast long-term Government of Canada bond yield. The 75 basis point change in allowed return on equity for every one percentage point in the forecast long term Government of Canada bond yield reflects some

[6] The five regulatory boards that use automatic adjustment mechanisms with a 0.75 adjustment factor are the EUB, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board, and the Régie de l'Energie de Québec. In Newfoundland and Labrador, the adjustment factor is 0.80.

recognition that the return on equity does not move in tandem (one for one) with changes in the yield on long-term government bonds.[7]

As indicated in Section II.C.1 above, the 2008 Alberta generic return on equity is 8.75% (at a long-term Canada bond yield of 4.55%). Yukon Electrical is proposing rates for a two-year test period, 2008-2009. I recommend that the PUB adopt a single benchmark return on equity for both test years, based on the average forecast long-term Government of Canada bond yield during the test years.

The most recent Consensus Economics, *Consensus Forecasts* (April 2008) indicates that the 10-year Government of Canada bond yield will be 3.6% in July 2008 and 3.9% by April 2009. During the first four months of 2008, the 10-year Government of Canada bond yield averaged approximately 3.7% (and the 30-year Government of Canada bond yield averaged 4.1%). Based on the actual yields to date and the *Consensus* for July 2008 and April 2009, the 10-year Government of Canada bond yield is forecast at approximately 3.7%. During April 2008, the spread between 10 and 30 year Canada bond yields averaged approximately 50 basis points. The addition of 50 basis points to the forecast 10-year bond yield produces a forecast 30-year Canada bond yield of 4.2% for 2008.

There is no consensus forecast for all of 2009. However, the long-term forecast for 10-year Government of Canada bond yields contained in the April 2008 Consensus Economics, *Consensus Forecasts* anticipates that the 10-year Government of Canada bond yield will be 5.0% in 2010. In the absence of a 2009 consensus forecast for Canada, the quarterly consensus forecasts for U.S. 10-year Treasury bond yields can be used to approximate the forecast for the 10-year Government of Canada bond yield, as the available consensus forecasts show that the Canadian and U.S. rates are expected to track

[7] While the 0.75 adjustment factor recognizes to some extent the inverse relationship between equity risk premiums and equity returns, it overstates the extent to which they move together. Nevertheless, to the extent that the automatic adjustment formula has reduced allowed ROEs since the inception of such formulas, it is reasonable for the formula to increase allowed ROEs by a similar amount until such time as a benchmark return is recalibrated and, if warranted, a new formula established.

closely, with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010. The Blue Chip *Financial Forecasts* (May 1, 2008) anticipates that the 10-year U.S. Treasury yield will increase quarterly by 0.10% during 2009. The resulting 10-year 2009 Government of Canada bond yield would be approximately 4.2%. Based on these forecasts and a continuation of the current 50 basis point spread between 10- and 30-year Canada bond yields, I anticipate that the 30-year Canada bond yield will average 4.7% in 2009.

The average forecast 30-year yield for the two test years is thus approximately 4.5%, similar to the 4.55% forecast relied on by the EUB to set the Alberta "benchmark" return of 8.75%. While the 2008-2009 average forecast long-term Canada bond yield of 4.5% is somewhat higher than the forecast for 2008 alone, Yukon Electrical is taking the risk that the actual long-term yields in 2009 will be higher than currently anticipated.

Based on a 4.5% long-term Canada bond yield forecast, the benchmark return on equity (ROE) for Yukon Electrical's 2008-2009 test years is approximately 8.75%, the same as the 2008 Alberta generic return on equity.

I recommend, therefore, that a benchmark return on equity of 8.75% be adopted for both test years; the 8.75% would be applicable to the common equity ratio estimated in Sections III to VIII. If, however, the common equity ratio adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

III. PRINCIPLES FOR CAPITAL STRUCTURE

The following principles should be respected when establishing the appropriate capital structure for Yukon Electrical:

A. The Stand-Alone Principle.
B. Compatibility of Capital Structure with Business Risks.
C. Maintenance of Creditworthiness/Financial Integrity.

Each of these principles is defined below.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by Yukon Electrical should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

Yukon Electrical is 100% owned by ATCO Electric. ATCO Electric, in turn, is a wholly-owned subsidiary of CU Inc. Yukon Electrical operates as a stand-alone entity (separate from the other electric utility operations of ATCO Electric). CU Inc. raises debt on behalf of Yukon Electrical. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities, including Yukon Electrical, at the cost incurred by CU Inc. Yukon Electrical's customers, therefore, receive the benefits of CU Inc.'s ratings. In turn, Yukon Electrical should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the

benefits of debt costs that reflect an A(high)/A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

Based on the indicated spreads for new issues as published by RBC Capital Markets, CU Inc. has been able to raise new 30-year debt on average at approximately 120 basis points over a similar term Government of Canada bond during 2007 and the first quarter of 2008. Over this period, spreads for utilities with one debt rating in the BBB category (split-rated utilities) have ranged from 135 basis points (Union Gas rated A by DBRS and BBB+ by S&P) to 175 basis points (EPCOR Utilities, rated A(low) by DBRS and BBB+ by S&P) and have averaged approximately 140-145 basis points (See Schedule 1).

The 2007-2008Q1 average masks the widening spreads over the period. As investors have become more risk-averse, and the outlook for the economy has deteriorated, credit spreads have widened considerably since the end of 2006. At the end of March 2008, the indicated spread for a new 30-year CU Inc. issue was 157 basis points versus 92 basis points at the end of 2006. Spreads for new split-rated A/BBB issues have increased from approximately 125-130 basis points to 200 basis points over the same period.

Depending on the state of the capital markets, the spread between the cost of a new long-term debt issue for a strong A credit and one for a split A/BBB credit can be much higher than it is currently. As recently as five years ago, the spread has been as high as 100 basis points.

With respect to electric power corporations that are still investment grade but rated in the BBB category by all the debt rating agencies, there is only one conventional equity corporation (i.e., non-income trust) included in the S&P/TSX Utilities Sector, TransAlta Corporation. The average indicated spread for a new 30-year TransAlta Corporation debt issue during 2007-2008Q1 has been 278 basis points; at the end of March 2008, the spread was 390 basis points. (Schedule 1) The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long term debt of approximately 233 basis points provides a perspective on the potential magnitude of the

benefits to ratepayers of Yukon Electrical's affiliation with CU Inc. As a true stand-alone entity, Yukon Electrical would not be able to obtain investment grade debt ratings given its small size. The estimation of an appropriate capital structure for Yukon Electrical should recognize the magnitude of the cost benefits conferred upon ratepayers arising from Yukon Electrical's ability to access debt capital through CU Inc. rather than on its own.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

For larger utilities like CU Inc. which regularly access the public debt markets, a reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult or weak capital market conditions.

As noted above, Yukon Electrical is too small to have its own debt ratings (i.e., it would not be investment grade) or to access the public debt markets on its own. If it were to access third-party debt on its own, its options would be limited to banks or insurance companies at a significantly higher cost than is available to CU Inc., and with more stringent covenants. A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to Yukon Electrical both the actual cost of debt that Yukon Electrical would be able to obtain on its own and the capital structure that would

be required by a potential lender to provide debt capital in the absence of its affiliation with CU Inc.

To my knowledge, the only small (total capital less than $100 million) regulated company that has accessed debt on a true stand-alone basis within the past five years is Natural Resource Gas (NRG), a small Ontario natural gas distributor. NRG was able to obtain five-year bank financing during 2005, a period of easy credit, at a spread over five-year Government of Canada bond yields of approximately 280 basis points. At the same time, the larger gas utilities (with debt ratings in the A/BBB rating categories) were able to issue five-year debt at spreads of 40-45 basis points over five-year Government of Canada bond yields. At the time, TransAlta Corporation was able to raise five-year debt at approximately 70 basis points above a similar term Government of Canada bond yield. While NRG is somewhat smaller (assets of approximately $9 million) than Yukon Electrical, it would be of reasonably similar business risk to Yukon Electrical. Thus NRG's stand-alone cost of debt provides a further indicator of the order of magnitude of the benefit that Yukon Electrical's ratepayers receive as a result of Yukon Electrical's affiliation with CU Inc.

My assessment of the appropriate capital structure for Yukon Electrical balances the stand-alone and creditworthiness and financial integrity principles with a recognition that the impact of small size on lenders' willingness to lend funds and on the stand-alone cost of debt would be, in part, related to the lack of liquidity and institutional interest in small debt issues rather than to fundamental business risk factors. Nevertheless, the appropriate capital structure and return on rate base for Yukon Electrical needs to recognize the cost benefits that Yukon Electrical's ratepayers receive.

IV. BUSINESS RISK

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short-term and long-term risks. Long-term risks are important because utility assets are long-lived. Moreover, utility stocks are not typically purchased as short-term investments. Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall higher return rewards when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future.

Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

Market demand risk relates to those factors that can lead to annual volatility in electricity sales or loss of customers. It includes market size, economic diversity and strength of the service area, growth potential, concentration of sales, competition with alternative energy sources and weather.

Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity. The physical risks of the utility are a function of its geography, mix of generation and ability to access alternative sources of supply.

The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed.

The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

Yukon Electrical is a small integrated electric utility serving 19 communities and approximately 15,000 customers spread throughout the territory. Whitehorse, the largest community, accounts for over 70% of the population of the Yukon. T he largest community served outside of Whitehorse is Watson Lake, with a population of approximately 1,600. T he populations of the other communities served range from approximately 10 to 300. Total sales in 2007 were approximately 300 GW.h. To put this in perspective, the following table compares customers, sales, and rate base of major Canadian investor-owned and government-owned electric utilities with rated debt, i.e., not guaranteed.[8]

Table 1

Company	Customers	Sales (GW.h.)	Rate Base ($ Millions)
Yukon Electrical	15,000	300	43
Electric Utilities with Rated Debt:			
ATCO Electric	216,000	10,300	1,500
EPCOR Utilities	318,000	7,100	500
FortisAlberta	430,000	14,700	800
FortisBC	152,000[1/]	3,100	680
Hydro One	1,300,000	29,300	8,400
Hydro Ottawa	280,000	7,500	500
Maritime Electric	66,000	1,000	200
Newfoundland Power	229,500	5,000	750
Nova Scotia Power	460,000	11,600	2,900

[8] For comparison with other northern electric utilities:

Company	Customers	Sales (MW.h.)	Rate Base ($ Millions)
NTPC[1/]	18,800	310,000	200
NU (YK)	7,900	157,000	20
NU (NWT)	2,600	35,000	12
YEC[1/ 2/]	15,000	302,000	158

[1/] Includes both direct and indirect customers.
[2/] Rate base approximated by 2006 net property, plant and equipment.

[1/] Includes both direct (approximately 100,000) and indirect customers.

As the table above indicates, Yukon Electrical is approximately one-quarter the size of the smallest utility (Maritime Electric) with its own debt ratings. Growth in rate base has been relatively strong over the past 10 years (approximately 3% annually). Future growth is expected to come from growth in new residential and commercial development and the continuing replacement of aerial infrastructure, i.e., exposed distribution lines, with underground lines. While rate base growth is expected to remain relatively strong, Yukon Electrical is expected to remain a very small utility relative to its Canadian peers. From a business risk fundamentals perspective, small size limits a utility's ability to diversify its risks geographically, operationally and among services provided.

Yukon Electrical's customer profile, based on 2007 actual data, is as follows:

Table 2

	Residential	**Commercial and Secondary[1/]**	**Street & Sentinel Lighting**	**Wholesale**
Sales ($000)	$14,088	$20,182	$837	$53
Customers	12,452	2,592	na	1

[1/] The majority of customers (2,570) and sales ($18,728) are commercial.

While Yukon Electrical currently has no industrial customers of its own, the economic base of the Yukon will have secondary impacts on the residential and commercial customer load. The cornerstones of the economy of the Yukon have historically been resource-based industries. The impact of these industries (principally mining) on the economy of the Yukon declined over the past decade following the closure of the Faro Mine in January 1997.[9] Prior to the mine's closure, the mining and oil and gas extraction industries had accounted for approximately 12% of GDP. In 2006, the portion of GDP accounted for the mining/oil and gas industries had fallen by half, to approximately 6%

[9] The mine was operated by Anvil Range Mining at the time of its closure.

(virtually all of which is accounted for by gold mining). The opening of the new Minto Mine in late 2007[10] is expected to have a positive impact on the economy, but will correspondingly increase the potential volatility in the economic performance of the Yukon.

The largest sector of the Yukon economy is public administration (government) contributing approximately 24% of GDP in 2006. This sector has a moderating impact on the territory's economy, because its rate of growth, while exhibiting some variability, is not subject to the wide swings seen in some other sectors, e.g. the resource-based sectors, manufacturing and construction. The importance of government to the economy of the Yukon is reflected in Yukon Electrical's customer profile/sales margin. Of Yukon Electrical's 18 largest customers, 11 are government-related entities, accounting for 17% of gross margin. Despite the moderating effect of government, annual GDP growth rates in the Yukon have been volatile, in part due to the year to year changes in construction activity. Over the 1998-2006 periods, annual GDP growth in the Yukon has been approximately twice as volatile as that of the individual provinces.

The divergent rates of growth in the Yukon over time demonstrate the volatility in the economy and potential impact on Yukon Electrical. Not only do the actual annual rates of growth exhibit considerable volatility, there can be significant differences between rates of growth as initially reported or forecast and the final actual rates of growth once all revisions have been made. For example, in May 2007, the Yukon Government, in its *Yukon Economic Overview and Outlook 2007* reported a 2005 rate of real GDP growth of 5.2%. The actual rate, as indicated above, was only 3.9% when revised in November 2007. The potential variance between forecast and actual rates of growth enhances Yukon Electrical's forecasting risk. On the cost side, forecasting risks are further increased by the tight labour market, particularly for skilled workers, rising wages and rising costs of basic materials.

[10] The mine is expected to connect to Yukon Energy in late 2008 and generate approximately 40 MW.h of sales. The costs associated with extending the transmission line to the mine are being paid by Minto Explorations Inc., the mine operator, and the Territorial Government.

Electric utilities, including Yukon Electrical, are subject to the risk of lost sales arising from the increasing emphasis on energy efficiency, conservation and reducing peak load. Lost load due to energy efficiency and conservation efforts reduces the utility's earnings. The implementation of energy conservation and efficiency initiatives, with the objective of reducing energy costs and environmental impacts raises the risk to earnings.[11] The Yukon Government is actively promoting energy efficiency through its Energy Solutions Center. Moreover, the elimination of Yukon Energy's Rate Stabilization Fund will act as an incentive for conservation.

With respect to supply and physical risks, Yukon Electrical faces a significantly higher level of risk relative to other Canadian electrical utilities. The electric utility network in the Yukon has two main grids: t he Whitehorse/Aishihik/Faro (WAF)[12] and the Mayo/Dawson grid.[13] The WAF grid is fed by Yukon Electrical's Fish Lake hydroelectric facility and Yukon Energy's Aishihik and Whitehorse hydroelectric plants. Yukon Electrical has backup generation to the WAF grid through its diesel standby plants at Carmacks, Ross River, Haines Junction/Canyon Creek and Teslin. Yukon Electrical's diesel plant at Stewart provides backup generation capacity to the Mayo/Dawson Grid. Yukon Electrical also serves a number of isolated communities (not connected to the grid) in the Yukon with diesel generation (Watson Lake, Beaver Creek, Destruction Bay/Burwash Landing, Old Crow, Pelly Crossing and Swift River). P elly Crossing is forecast to be connected to the WAF grid in the 4th quarter of 2008.

Approximately 12% of Yukon Electrical's rate base is comprised of generation assets (approximately 90% of which is diesel). The presence of generation assets in rate base generally increases the business risk of Yukon Electrical relative to a pure distribution utility, as the operational risks associated with generation exceed those of "wires"

[11] A number of regulatory jurisdictions in North America have implemented or are investigating revenue decoupling (decoupling revenues from consumption) to address this issue.
[12] The WAF grid connects Whitehorse with Yukon Electrical's franchise communities of Carcross, Carmacks, Haines Junction/Canyon Creek, Ross River and Teslin.
[13] The Mayo/Dawson grid connects Yukon Electrical's franchise communities of Stewart Crossing and Keno Hill with Yukon Energy's franchise communities of Dawson City, Elsa and Mayo.

554 operations. In the case of Yukon Electrical, the operating risks are exacerbated by the
555 severe climate in which the utility operates, increasing both the risk of outages and the
556 potential unanticipated impacts of repair (in terms of both time and expenditures), and the
557 isolated nature of some of the smaller communities served. While Yukon Electrical has
558 proposed deferral accounts that cover diesel fuel costs, the high cost of diesel fuel creates
559 an additional incentive to conserve energy (thus leading to lower than expected sales).
560 Further, in contrast to hydroelectric generation, diesel generation is exposed to greater
561 risks of complying with increasingly stringent environmental standards. Yukon
562 Electrical has a significant amount aerial infrastructure, i.e., exposed distribution line.
563 Although the exposed lines are being moved underground, the exposed lines, in
564 conjunction with a heavily treed service territory, increases the operating risks of Yukon
565 Electrical.
566
567 With respect to regulatory risk, as independent tribunals, regulators have the power to
568 expose utilities to relatively high risks, by, for example, disallowing costs, approving rate
569 designs that are tilted against recovery of fixed costs, or returns that do not conform to
570 informed investors' perception of risk. Alternatively, regulation can provide an
571 environment characterized by even-handedness, conducive to continued growth
572 consistent with economic allocation of resources, and affording the utility an opportunity
573 to achieve a fair return with a reasonably high probability. This explains why regulation
574 is considered to be a key element of a utility's business risk profile. On balance, the
575 regulatory environment in the Yukon has been even-handed and reasonable in its
576 approach; the Board has granted deferral accounts for costs that are beyond the control of
577 management, including power costs, diesel fuel and generation costs, plant maintenance
578 expense and rate case expense.[14] Nevertheless regulatory decisions can also have a
579 negative impact on utilities.
580
581 Ms. McShane has no reason to conclude that, based on current policies and practice, that
582 Yukon Electrical, similar to other regulated utilities in North America, will not be

[14] The existence of these deferral accounts does not constitute a guarantee that the costs accrued in the account will be recoverable from customers.

provided a reasonable opportunity to recover its capital investment. Nevertheless, the regulator cannot provide a guarantee that the capital investment will be recovered. The regulator can not provide a guarantee that long-term economic conditions will permit the full recovery of the invested capital, it does not make energy policies that can favor the government-owned utility and/or impact on the ability to recover the invested capital, and it cannot bind the decisions of future regulators.

On balance, as a very small utility operating in a service territory with an undiversified economic base and facing significant geographic physical/operating challenges, Yukon Electrical:

- is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada,
- is of higher than average business risk within the spectrum of Canadian utilities and,
- is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited.

V. CAPITAL STRUCTURES OF PEERS

The determination of the capital structure that reflects Yukon Electrical's business risks and would be compatible with the application of the benchmark return on equity requires comparisons with the capital structures of other electric utilities for two reasons. First, electric utilities which raise debt in the public markets (and, therefore, have debt ratings) have capital structures that have been "tested" by the capital markets. Thus, their capital structures, in conjunction with other key financial metrics (e.g., coverage ratios), provide an indication of the capital structure required to maintain investment grade debt ratings. Second, the common equity ratios allowed for other electric utilities (whether or not their debt is rated), either through regulatory decisions or settlements, provide a measure of the

level that is warranted for an electric utility to compete for capital with its peers, with due regard to differences in business risk.

Table 3 below sets out the average actual common equity ratios of Canadian electric utilities with rated debt, as well as those of low risk U.S. electric utilities with debt rated in the A category.

Table 3

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	43.4%
Transmission & Distribution	A/Baa1/A-	44.5%
Integrated	A(low)/Baa2/BBB+	40.5%
U.S. A-rated Electric Utilities	na/A2/A	49.0%

Source: Schedules 2, 3 and 4.

Table 3 indicates that the average actual common equity ratios for all Canadian electric utilities with rated debt and for Canadian transmission and distribution utilities have averaged close to 43.5% and just below 45% respectively. The corresponding debt ratings by all three debt rating agencies have been, on average, approximately A-/A(low).

Given Yukon Electrical's higher than average business risks, the equity ratios maintained by other Canadian electric utilities indicate that a 45% common equity ratio would be too low to fully compensate for its business risks. Two of the smaller investor-owned primarily electric distribution utilities that would be considered the closest comparators to Yukon Electrical of the Canadian electric utilities with rated debt (Maritime Electric and Newfoundland Power) both have target actual common equity ratios of 45%. While they are the closest comparators, both are significantly larger and face lower business risk than Yukon Electrical. Moreover, their allowed returns on common equity are higher than the returns allowed under the Alberta formula which serves as the benchmark return on

equity for Yukon Electrical.[15] These specific "comparators" strengthen the conclusion that a 45% common equity ratio for Yukon Electrical (at the benchmark return on equity) is too low to fully compensate for Yukon Electrical's business risks. With respect to the recent Northwest Territories Power Corp. (NTPC) decision, for the 2007/08 test year, the Public Utilities Board of the Northwest Territories adopted a common equity ratio of 48.86% and an incremental equity risk premium of 0.50% for NTPC, a higher business risk utility than Yukon Electrical. The corresponding equity ratio for NTPC that would fully compensate for its higher business risks would be approximately 56-57%. Since NTPC faces higher business risk than Yukon Electrical, the fully compensatory equity ratio for Yukon Electrical indicated by the NTPC decision would be lower than 56-57%.

As the capital market has become increasingly global, Canadian utilities increasingly find themselves competing with foreign utilities for financing. The similarities and proximity of the U.S. and Canadian capital markets make comparisons with U.S. electric utilities especially relevant. The major bond rating agencies increasingly draw comparisons between Canadian utilities and their U.S. peers. Thus, the capital structures of U.S. electric utilities of reasonably similar business risk to Yukon Electrical and with debt rated in the A category may provide some guidance.

Since 1999, S&P has assigned to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest.[16] As of November 2007, the median business profile score of the U.S. electric utilities with debt rated in the A category was "4".[17] By comparison the average S&P business profile score assigned to Canadian utilities has been "3". Like Yukon Electrical, the majority of these

[15] Maritime Electric, which is not subject to an automatic adjustment formula, was allowed a common equity return of 10.0% for the 2008 test year, approximately 125 basis points higher than the EUB's generic return on equity for the same test year. Newfoundland Power's allowed return on equity at a 4.55% long-term Government of Canada bond yield would be 8.91%.

[16] The key qualitative factors that S&P evaluates in assessing the business risk of regulated electric utilities include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness.

[17] In November 2007, S&P integrated its utility business/financial risk evaluation methodology into its broader corporate ratings matrix and no longer provides as detailed or transparent a matrix for utilities.

companies are largely "wires" or "pipes" companies.[18] However, as discussed in Section IV, Yukon Electrical would be viewed as facing higher business risks than the typical Canadian utility. On balance, based on its business risk fundamentals, Yukon Electrical would, on a stand-alone basis, be assigned a business profile score within the "4" category, higher than the typical Canadian utility, but the same as the A rated U.S. utilities.

The higher business risk of the U.S. electric utilities relative to the typical Canadian electric utility is reflected in their higher common equity ratios, leading to similar debt ratings. As indicated in Table 3 above, the median 2006 actual common equity ratio of U.S. electric utilities with debt rated in the A category was 49.0%. Given the similarity in the level of business risks between the A rated U.S. electric utilities and Yukon Electrical, in isolation,[19] the 49% median equity ratio is a reasonable benchmark for Yukon Electrical.

With respect to allowed common equity ratios, Table 4 below summarizes the most recently adopted capital structures for major Canadian electric utilities, along with any applicable incremental equity risk premiums. Unlike Yukon Electrical, both NTPC and Yukon Energy are government-owned utilities whose debt is guaranteed by their respective Territorial governments. However, like Yukon Electrical, they are both northern utilities, and they are both largely treated like investor-owned utilities for purposes of establishing capital structure and return on equity.

[18] Newfoundland Power, for example, was assigned a business risk profile score of "3". Newfoundland Power would be considered to face lower business risks than Yukon Electrical, given its size, service area and more comprehensive slate of deferral accounts, including revenue protection against weather variations.

[19] As discussed in more detail in Section VII, the debt ratings of utilities in a particular business risk category are not solely driven by capital structures. They are also driven by other financial parameters, including coverage ratios. Coverage ratios are a function of cash flows, which, in turn, are dependent upon equity returns. The common equity return for the A rated U.S. electric utilities has averaged 11.8% over the past three years (2004-2006), compared to the 8.75% benchmark return. Taking the actual common equity ratios and ROEs of the A rated utilities together, a 50% common equity ratio for Yukon Electrical at the benchmark 8.75% ROE would be too low to equate Yukon Electrical to a benchmark utility.

Table 4

Alberta Taxable Distributors	37.0%
FortisBC	40.0% (plus 0.40% risk premium above BCUC's low risk utility benchmark)
Maritime Electric	42.7% (ROE has been approximately 1.25% higher than Canadian average)
Newfoundland Power	44.5% (risk premium 0.15% higher than benchmark)
Northwest Territories Power	48.6% (plus 0.50% risk premium)
Nova Scotia Power	37.5% (ROE approximately 0.75% higher than Canadian average)
Ontario Electric Distributors	40.0%
Yukon Energy	40.0% (plus 0.52% risk premium above BCUC's low risk utility benchmark) [1/]

[1/] Equal to average of the incremental equity risk premiums of Pacific Northern Gas (65 basis points) and FortisBC (40 basis points); by Order in Council, Yukon Energy's return on equity is then reduced from the "fair return on common equity" by 0.50%.

Source: Schedule 5.

If the capital structure for each of the utilities in Table 4 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47%. On average the companies included in Table 4 are of lower business risk than Yukon Electrical. On this basis, the common equity ratio for Yukon Electrical necessary to compensate for its business risks would be higher than 46-47%.

With respect to U.S. electric utilities, since the beginning of 2005, the average common equity ratio adopted for ratemaking purposes has been 47.9%.[20] The average business profile score of all U.S. electric utilities rated by S&P is "5". Thus, the business risk of the U.S. electric utility industry as a whole is higher than that of Yukon Electrical. However, the average debt rating of all U.S. electric utilities is only BBB. Consequently, it may be inferred that a common equity ratio of 47.5% is not adequate for a "5" business profile score and an A credit rating. Given Yukon Electrical's lower fundamental business risks than the U.S. industry in the aggregate, but higher target debt rating (in the A category), the U.S. electric industry average allowed common equity ratio suggests that

[20] Regulatory Research Associates, *Major Rate Case Decisions, January–March 2008*, April 2, 2008. Allowed returns on equity have averaged 10.4% over the same period.

a 47.5% common equity ratio would constitute a floor for the equity ratio required to equate Yukon Electrical to the benchmark utility.

On balance, the actual and allowed equity ratios of other Canadian electric utilities, and those of U.S. electric utilities (in conjunction with their actual and allowed ROEs) indicate that the common equity ratio required to fully compensate for Yukon Electrical's business risks would be no less than 47.5%.

VI. RATING AGENCY DEBT RATIO GUIDELINES

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), S&P has published the most detailed matrix of quantitative guidelines for different debt ratings.[21] For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds From Operations (FFO)[22] Interest Coverage, and FFO to Total Debt (discussed in Section VII). S&P does not apply their guidelines mechanistically; however, the guidelines do represent one objective basis for evaluating an appropriate stand-alone capital structure for Yukon Electrical.

S&P's debt ratio guidelines for an A debt rating and a business risk score of "4", the notional business risk score attributed to Yukon Electrical, are as follows:

Table 5

Total Debt/Total Capital	45.0-52.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

The guidelines for a business risk profile score of "4" indicate that a common equity ratio in the range of 48% to 55% (mid-range of 50.0-52.0%) is warranted for an A rating.

[21] DBRS has published guidelines, but the guidelines have not distinguished by either business risk or investment grade rating category.
[22] FFO means Funds from Operations, which equal net income plus non-cash items, including depreciation, deferred taxes and other non-cash expenses, e.g., amortization of regulatory assets.

Moody's also has published quantitative guidelines. As with S&P, other factors may outweigh the mechanistic application of the guidelines in determining a rating. However, the guidelines provide "broad guidance on the ratio ranges that may generally be seen at different rating levels".[23] While neither Yukon Electrical nor CU Inc. has a Moody's rating, there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's. Thus Moody's guidelines are applicable to those companies and, in turn, will play a role in the formation of target capital structures among Canadian utilities, with the objective of maintaining investment grade debt ratios.

Canadian distribution utilities are typically considered to be operating in a "low business risk" environment by Moody's due to the high degree of regulation and a supportive regulatory system. However, due to its specific business risk fundamentals and small size, Yukon Electrical would likely be classified within the "medium business risk" category. Moody's debt ratio guidelines for an A rating for a regulated company of "medium risk" are:

Table 6

Debt/Capital	40.0-60.0%

Source: Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

Based on Moody's debt ratio guidelines, a reasonable common equity ratio for Yukon Electrical compatible with a stand-alone A rating would be in the middle of the range, i.e., approximately 45%-55%.

The S&P and Moody's debt ratio guidelines, taken together, support a common equity ratio of approximately 45%-55% (mid-point of 50%).

[23] Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005, page 8.

VII. RATING AGENCY GUIDELINES OTHER THAN DEBT RATIO

Based on the actual and allowed equity ratios for other Canadian and low risk U.S. electric utilities (Section V), the rating agency debt ratio guidelines (Section VI) and consideration of Yukon Electrical's relative business risk (Section IV), a common equity ratio range of 47.5%-52.5% (mid-point of 50%) would be required to equate Yukon Electrical to the benchmark utility (i.e., one with a credit rating of A).

However, the common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Both S&P and Moody's consider cash flow coverage ratios to be key quantitative financial metrics, specifically FFO Interest Coverage and FFO/Total Debt. If a utility is able to achieve adequate cash flow coverage ratios, despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of return on equity, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's and Moody's guideline ranges for the debt ratio, while an important indicator of an appropriate capital structure, should be referenced with regard to other financial metrics.

Table 7

	S&P	**Moody's**
	"4"	"Medium Risk"
FFO Interest Coverage	3.5-4.2X	3.5-6.0X
FFO/Average Total Debt	20.0-28.0%	22.0-30.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006 and Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

I have estimated the FFO Interest Coverage and FFO/Total Debt ratios for Yukon Electrical based on common equity ratios of 47.5% and 52.5%. Specifically, I estimated the ratios using capital structures containing 47.5% and 52.5% equity, each in conjunction with a benchmark return on equity of 8.75%, Yukon Electrical's forecast

embedded cost of debt of 6.83% and forecast depreciation expense for 2009. In interpreting the results, it is important to recognize, as noted earlier, that the guidelines are not applied mechanistically.

Yukon Electrical's indicated FFO Interest Coverage ratios are 4.2X and 4.7X at 47.5% equity and 52.5% equity respectively. The indicated ratios are at the upper end of S&P's guideline range at a 47.5% common equity ratio and above the upper end of the range at a 52.5% common equity ratio. In each case, the calculated FFO coverage ratio is below the mid-point (4.75X) of Moody's guideline range. The estimated FFO/Total Debt ratios (22% and 25% at common equity ratios of 47.5% and 52.5% respectively) are within both S&P's and Moody's guideline ranges. Table 8 (below) indicates that an FFO Interest Coverage ratio for Yukon Electrical in the range of 4.2X to 4.7X would be higher than the achieved ratios of other Canadian transmission and distribution utilities (3.8X), which would be reasonable given Yukon Electrical's higher business risk. However, at a 52.5% equity ratio, the ratio would be similar to, but still lower than, the average FFO coverage ratios achieved by the low risk (A rated) U.S. electric utilities (4.9X).

As shown in Table 8, an FFO/Total Debt ratio for Yukon Electrical of 22% to 25% would be higher than the average achieved FFO/Total Debt ratios of other Canadian electric utilities (17.5%), but, at a 47.5% equity ratio, similar to the average of the low risk (A rated) U.S. electric utilities (22.3%).

Table 8

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	FFO Interest Coverage (2004-2006)	FFO to Total Debt (2004-2006)
Canadian Electric Utilities:			
All	A/Baa1/A-	3.5X	17.5%
Transmission & Distribution	A/Baa1/A-	3.8X	17.5%
Integrated	A(low)/Baa2/BBB+	3.3X	14.2%
U.S. A-rated Electric	na/A2/A	4.9X	22.3%

Source: Schedules 2 and 3.

Although S&P no longer publishes a guideline range for pre-tax (or EBIT)[24] interest coverage ratios,[25] it is still considered an important quantitative financial ratio by all three debt rating agencies (S&P, DBRS and Moody's). It has also been a key ratio considered by regulators (e.g., EUB and BCUC) in assessing capital structures. Moreover, in contrast to the FFO coverages, which are driven in part by depreciation expense, EBIT coverage is more a function of capital structure and return on equity.

S&P's most recent EBIT interest coverage guideline range for an A rating at a "4" business profile score was 3.3X to 4.0X.[26] At common equity ratios of 47.5% and 52.5%, the benchmark return on equity of 8.75%, Yukon Electrical's embedded debt cost of 6.83%, and an income tax rate of 34%,[27] Yukon Electrical's EBIT interest coverage would be in the range of approximately 2.8 to 3.2X. Table 9 below demonstrates the calculation of the EBIT interest coverage at a 50% common equity ratio.

Table 9

	Cost Rate	**Percentage**	**Weighted Component**
	(1)	(2)	(3)=(1) x (2)
Debt	6.83%	50.00%	3.42%
Common Equity	8.75%	50.00%	4.375%
Tax Rate (t)	34%		
Income Tax = 4.38 x (t/(1-t))			2.25%
Pre-Tax Return			10.04%
EBIT Interest Coverage[1/]			2.94X

[1/] EBIT Interest Coverage = Pre-Tax Return ÷ Weighted Debt Component.

The indicated EBIT interest coverage ratios of 2.8X to 3.2X at common equity ratio of 47.5-52.5% are below the bottom end of S&P's guideline range for an A rating.

[24] Earnings before Interest and Taxes.
[25] Moody's has not, to my knowledge, ever published an EBIT interest coverage guideline.
[26] S&P, *Utilities and Perspectives*, June 1999. The EBIT interest coverage guideline ranges were excluded from the quantitative guidelines after June 2004, but the actual EBIT interest coverage ratios continue to be provided in the annual utilities' *CreditStats* published by S&P.
[27] Statutory combined Federal (19%) and Yukon Territory (15%) rate as of 2009.

Table 10 below indicates that an EBIT interest coverage ratio in the range of 2.8X to 3.2X would be somewhat higher than the average for the other Canadian electric utilities. Over the period 2004-2006, the average EBIT coverage ratios for all major Canadian electric utilities and transmission and distribution utilities with rated debt were 2.7X and 2.5X respectively. In light of Yukon Electrical's higher than average business risk, an EBIT interest coverage ratio higher than the Canadian electric utility industry average should be expected. A ratio of 3.2X, however, would still be lower than the 3.6X average EBIT interest coverage ratio achieved by low risk (A rated) U.S. electric utilities, which, is partly attributable to the low risk U.S. utilities' higher achieved returns on equity (11.8%, see Schedule 2) relative to the 8.75% benchmark return on equity.

Table 10

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	EBIT Interest Coverage (2004-2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	2.7X
Transmission & Distribution	A/Baa1/A-	2.5X
Integrated	A(low)/Baa2/BBB+	2.6X
U.S. A-rated Electric	na/A2/A	3.6X

Source: Schedules 2 and 3.

In summary, my estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of the 47.5% to 52.5% range (i.e. at 52.5%).

VIII. DEBT RATING AGENCY COMMENTARY

As indicated in Sections VI and VII above, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a utility. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity base on which it is allowed to earn, but also the allowed return on equity and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S. The investment community has also indicated to the National Energy Board that it believes the financial parameters adopted for regulated companies are too low.[28]

DBRS

DBRS has commented generally on the relatively low common equity ratios and returns that are being allowed in Canada. In a May 2003 commentary, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, DBRS noted that it would like to see both the deemed common equity ratios increased as well as increases in allowed returns to levels more consistent with U.S. returns.

In December 2004, subsequent to the EUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity ratios and equity returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (return on equity) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

[28] National Energy Board, *Canadian Hydrocarbon Transportation System*, August 2005, June 2006 and July 2007.

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[29] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.[30]

Standard and Poor's

With respect to S&P, in early March 2003, the debt rating agency announced that it was reevaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation).

S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

Like DBRS, S&P has made references to the low deemed equity ratios and equity returns allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. For example, S&P commented on the thin equity layers (and the low returns) allowed the ATCO group of utilities after the EUB decision, stating,

[29] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The return on equity of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower return on equity is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

[30] Other DBRS reports have referenced the low approved returns on equity as a "challenge" for Canadian utilities, i.e., ATCO Ltd. (January 2007), CU Inc. (January 2007), Union Gas (March 2007) and FortisAlberta (May 2007).

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004)

In a more recent report for Yukon Electrical's parent, CU Inc. (rated A), S&P stated in reference to the company's businesses in Alberta,

> Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities (S&P, *CU Inc.*, October 26, 2007)

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[31] As indicated above, the "aggressive leverage" is largely a result of regulatory directives.

In sum, the debt rating agencies consider the allowed common equity ratios for Canadian utilities to be relatively thin and the allowed ROEs to be relatively low. (Actual equity ratios will generally track allowed equity ratios, as utilities have no incentive to maintain higher equity ratios than allowed by the regulator for ratemaking purposes.)

Based on the views of the debt rating agencies, in the aggregate, the allowed and actual common equity ratios of other Canadian electric utilities would be on the low side as a point of departure for estimating a reasonable capital structure for Yukon Electrical. In that context, the upper end of a 47.5%-52.5% common equity range would be reasonable for Yukon Electrical and allow the benchmark return on equity to be applied without an incremental equity risk premium.

[31] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

IX. CHOICE OF CAPITAL STRUCTURE AND RISK PREMIUM

As previously discussed, I have estimated the common equity ratio that would fully compensate for Yukon Electrical's business risk, i.e., the upper end of a range of 47.5% to 52.5%. A common equity ratio of 52.5% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained. To reach an actual common equity ratio of 52.5%, there would need to be a material equity infusion would be required to bring the actual equity ratio up to 52.5%.[32]

There is a critical concern, however, with this approach. While the shareholders may be willing to accept the Alberta benchmark return on equity as a point of departure for setting the allowed return on equity for Yukon Electrical, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in Yukon Electrical (as well as shareholders in other Canadian utilities with similar allowed returns) consider the allowed returns for Canadian utilities to be to low to be compatible with the fair return standard begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return. In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities over the period 2005-2008Q1 has been approximately 10.4%, approximately 1.5 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-13.8%.[33]

[32] In principle, the common equity ratio could be simply deemed to be 52.5% irrespective of Yukon Electrical's actual common equity ratio. This is not without precedent. For example, the Ontario Energy Board has deemed common equity ratios of 40% for all of the electricity distributors under its jurisdiction. The actual equity ratios of the distributors at the end of the 2006 ranged from negative to 100%. However, Canadian regulators generally have been reluctant to adopt deemed common equity ratios that are materially higher than the actual equity ratios that are maintained by the utilities.

[33] The Conference Board of Canada, in reference to allowed returns for U.S. electricity transmission, underscored the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled Electricity Restructuring: Opening Power Markets, the Conference Board stated,

This consideration leads me to recommend that Yukon Electrical move to an equity ratio of 47.5%, with the difference between a 47.5% equity ratio and the 52.5% ratio that would fully compensate for Yukon Electrical's business risks reflected in an incremental equity risk premium. The estimate of the risk premium recognizes that within the five percentage point range of equity ratios (from 47.5% to 52.5%), the overall cost of capital would be relatively constant. In other words, as the equity ratio moves from 52.5% to 47.5%, the overall cost of capital would not change; the decrease in the equity ratio would be offset by an increase in the common equity return. As demonstrated in Table 11 below, a decrease in the common equity ratio from 52.5% to 47.5% increases the equity return from the 8.75% benchmark return on equity to approximately 9.25%.[34]

Table 11

	Proportion	Cost	Weighted Component
Debt	47.50%	6.15%	2.92%
Equity	52.50%	8.75%	4.59%
			7.52%
		Tax Allowance at 34%	2.37%
		Pre-Tax Cost of Capital	9.88%
Move Equity Proportion to 47.5%			
Pre-Tax Cost of Capital Remains Unchanged at:			9.88%
Less: Weighted Interest Component (6.15% x 52.5%)			3.23%
Pre-Tax Weighted Equity Component			6.65%
Less: Tax at 34%			2.26%
After-Tax Weighted Equity Component			4.39%
ROE at 47.5% Equity			
(After-Tax Weighted Equity Component / 47.5%)			**9.24%**

Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.

The same conclusions are relevant to distribution and generation.

[34] Based on a cost of debt equal to the 4.55% forecast 30-year Long Canada yield plus the November 30, 2007 indicated spread for a new 30-year CU Inc. debt issue of 130 basis points, and the 2009 statutory corporate income tax rate of 34%.

The indicated required increase in the common equity return due to the lower equity ratio, and thus the required incremental equity risk premium for Yukon Electrical at a 47.5% ratio, is approximately 0.50%. A 0.50% incremental equity risk premium results in a recommended ROE for Yukon Electrical of 9.25%.

X. CONCLUSIONS

- I have relied on the approach adopted by the EUB and NEB with respect to capital structure, that is, I have estimated the capital structure that fully reflects the business risk of Yukon Electrical.

- The return on equity that would be applied to the capital structure that fully compensates for Yukon Electrical's business risk is the EUB's benchmark return on equity established in Decision 2004-052, as adjusted for changes in the forecast long-term Canada bond yield.

- I recommend that the YUB adopt a single benchmark return on equity for both test years, 2008-2009, of 8.75%, based on the average forecast of long-term Canada bond yields over the period of 4.5%.

- The capital structure for Yukon Electrical should:
  - Respect the stand-alone principle;
  - Be compatible with Yukon Electrical's business risks; and,
  - Maintain Yukon Electrical's creditworthiness and financial integrity.

- Yukon Electrical's business risks are higher than those of the typical Canadian electricity distribution utility and higher than average within the spectrum of Canadian utilities.

- The actual and allowed capital structures of Yukon Electrical's peers, both Canadian and U.S., indicate that, in isolation, the common equity ratio that would equate Yukon Electrical to a benchmark utility would be no less than 50%; taking explicit account of U.S. utilities' considerably higher ROEs relative to the benchmark ROE of 8.75% supports an equity ratio in excess of 47.5%.

- Debt rating agency guidelines for the debt ratio compatible with Yukon Electrical's level of business risk support a common equity ratio in the range of 45-55%.

- Estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of a 47.5% to 52.5% range (i.e. at 52.5%).

- The concerns expressed by the debt rating agencies, as well as other capital market participants, that the common equity ratios of Canadian utilities are too thin (and the ROEs are too low) further support the focus on the upper end of common equity ratio range for Yukon Electrical of 47.5% to 52.5%.

- In sum, the upper end of a 47.5-52.5% common equity range would be reasonable for Yukon Electrical and would allow a benchmark return on equity to be applied without an incremental equity risk premium.

- One critical factor militates against increasing the actual common equity ratio of Yukon Electrical to 52.5%: To require shareholders to commit additional equity capital to have the opportunity to earn an equity return perceived as too low is fundamentally incongruous.

- To address this factors, I recommend increasing the actual common equity ratio of Yukon Electrical to 47.5% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a 47.5% common equity ratio, the allowed ROE for Yukon Electrical should be set at 9.25% for the 2008 and 2009 test years.

APPENDIX A
QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN & CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000

Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001

Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company/Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

1

2

Current Ratings and New Issue Indicated Spreads
Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities

	Current Ratings April 1, 2007		4-10-06	6-12-06	9-5-06	11-6-06	1-2-07	2006 Average	4-2-07	7-3-07	10-9-07	11-26-07	2007 Average	4-1-08	2007-2008Q1 Average
	DBRS	S&P													
A Rated															
CU Inc.	A(high)	A	90	94	97	93	92	**93**	90	95	115	130	**108**	157	**117**
Enbridge Gas	A	A-	100	105	100	96	95	**99**	98	110	115	130	**113**	170	**125**
Enbridge Pipelines	A(high)	A-	100	105	100	96	95	**99**	98	105	115	130	**112**	170	**124**
Gaz Metro	A	A	89	94	99	95	97	**95**	94	92	115	135	**109**	172	**122**
Terasen Gas [1/]	A	A	na	na	na	na	na	**na**	na	122	135	145	**134**	168	**143**
TransCanada PipeLines	A	A-	117	120	120	116	115	**118**	115	130	140	160	**136**	215	**152**
Average	**A**	**A-**	**99**	**104**	**103**	**99**	**99**	**101**	**99**	**109**	**123**	**138**	**117**	**175**	**130**
Median	**A**	**A-**	**100**	**105**	**100**	**96**	**95**	**99**	**98**	**108**	**115**	**133**	**113**	**170**	**124**
Split Rated A/BBB															
EPCOR Utilities	A(low)	BBB+	129	132	133	130	135	**132**	130	136	170	185	**155**	255	**175**
Nova Scotia Power	A(low)	BBB	135	140	142	140	138	**139**	132	136	145	170	**146**	205	**158**
Terasen Gas [1/]	A	A	129	145	142	130	130	**135**	119	na	na	na	**119**	na	**119**
Union Gas	A	BBB+	118	123	120	114	107	**116**	109	109	120	150	**122**	185	**135**
Westcoast Energy	A(low)	BBB+	123	128	125	120	118	**123**	119	119	125	155	**130**	185	**141**
Average	**A(low)**	**BBB+**	**127**	**134**	**132**	**127**	**126**	**129**	**122**	**125**	**140**	**165**	**138**	**208**	**145**
Median	**A(low)**	**BBB+**	**129**	**132**	**133**	**130**	**130**	**131**	**119**	**128**	**135**	**163**	**136**	**195**	**141**
BBB Rated															
TransAlta	BBB	BBB	162	168	168	162	170	**166**	170	205	300	325	**250**	390	**278**

[1/] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.8	11.4	3.1
CU Inc.	2.7	18.7	3.6
Enersource	2.1	16.7	3.8
ENMAX Corp.	6.4	46.3	8.1
EPCOR Utilities Inc.	3.0	23.4	4.2
FortisAlberta Inc.[2/]	2.3	17.5	3.0
FortisBC Inc.[2/]	2.2	10.9	2.8
Hamilton Utilities	3.4	32.0	4.7
Hydro One Inc.	3.2	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	26.1	5.7
Maritime Electric	2.5	12.9	2.6
Newfoundland Power [2/]	2.4	14.0	2.9
Nova Scotia Power	2.4	14.2	3.3
Toronto Hydro	2.7	17.5	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	12.5	3.0
Gaz Metropolitain	2.5	24.0	4.6
Pacific Northern Gas [4/]	2.4	26.4	3.2
Terasen Gas	2.0	9.7	2.4
Union Gas [3/]	2.1	12.8	2.8
Pipelines			
Enbridge Pipelines [3/]	3.3	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	15.7	2.8
Westcoast Energy Inc.	2.1	16.4	3.1
Medians			
Electric T&D	**2.7**	**17.5**	**3.8**
Electric Integrated	**2.5**	**14.2**	**3.3**
All Electric	**2.6**	**17.5**	**3.5**
Gas Distributors	**2.1**	**12.8**	**3.0**
All Companies	**2.4**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

Name	S&P Debt Rating	S&P Business Profile	Average 2004-2006 Debt Ratio	Average 2004-2006 EBIT Coverage	Average 2004-2006 FFO/Debt	Average 2004-2006 FFO Coverage	Average ROE 2004-2006
Alabama Power Co.	A	4	54.3	4.3	22.8	5.6	13.5
Central Hudson Gas & Electric Corp.	A	3	66.3	4.7	16.7	4.3	12.2
Consolidated Edison Co. of New York Inc.	A	2	54.8	2.8	18.7	3.9	10.0
Consolidated Edison Inc.	A	2	57.2	2.6	16.7	3.7	9.2
Duke Energy Carolinas LLC	A-	4	48.0	4.0	28.8	14.9	NA
Duke Energy Corp.	A-	5	48.7	3.2	19.8	3.9	9.9
Duke Energy Indiana Inc.	A-	4	56.7	3.1	17.6	4.6	8.8
Duke Energy Ohio Inc.	A-	5	38.7	4.5	23.2	5.6	11.0
Florida Power & Light Co.	A	4	41.1	5.9	34.1	7.7	11.7
FPL Group Inc.	A	5	51.8	2.7	22.3	4.5	12.4
Georgia Power Co.	A	4	56.0	4.6	22.0	6.1	14.1
Gulf Power Co.	A	4	54.5	3.7	20.9	4.6	12.2
Integrys Energy Group Inc.	A-	5	58.6	3.4	13.8	4.1	12.5
KeySpan Corp.	A-	3	61.8	3.5	16.2	3.9	10.4
Madison Gas & Electric Co.	AA-	4	52.4	4.5	20.4	5.1	10.6
MidAmerican Energy Co.	A-	5	52.4	4.4	26.0	5.8	14.2
MidAmerican Energy Holdings Co.	A-	4	74.9	1.9	11.1	2.5	13.2
Mississippi Power Co.	A	4	63.0	4.2	22.8	10.8	13.9
NSTAR	A+	1	65.4	3.5	22.6	4.9	13.3
NSTAR Electric Co.	A+	1	49.7	5.7	39.4	8.1	13.8
Orange and Rockland Utilities Inc.	A	2	70.8	3.6	16.9	3.9	NA
PacifiCorp	A-	5	59.0	2.5	15.0	3.7	7.0
PPL Electric Utilities Corp.	A-	3	51.0	3.1	26.2	4.9	NA
San Diego Gas & Electric Co.	A	5	54.8	5.0	25.9	6.7	16.3
SCANA Corp.	A-	4	57.6	2.5	22.5	4.2	11.4
South Carolina Electric & Gas Co.	A-	4	50.1	2.6	25.6	5.1	10.3
Southern Co.	A	4	57.0	3.8	22.3	5.3	14.9
Vectren Corp.	A-	4	60.4	2.7	15.9	3.9	10.5
Wisconsin Electric Power Co.	A-	4	52.5	4.8	25.0	6.8	11.8
Wisconsin Power & Light Co.	A-	4	48.1	3.6	31.1	5.9	9.9
Wisconsin Public Service Corp.	A	4	52.3	4.0	22.3	5.4	10.1
Mean	**A**	**4**	**55.5**	**3.7**	**22.1**	**5.5**	**11.8**
Median	**A**	**4**	**54.8**	**3.6**	**22.3**	**4.9**	**11.8**

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 1, 2007;
Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, November 9, 2007; and *Credit Stats,* September 2007.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures (DBRS)	A		A-	
	Issuer (S&P)				
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
TransCanada PipeLines	Senior Secured	A		A	Very conservative
	Senior Unsecured	A	A2	A-	
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Electric T&D		**A**	**Baa1**	**A-**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**BBB+**	**Very conservative**
All Electric		**A**	**Baa1**	**A-**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
All Companies		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd.[4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Electric Utilities									
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55	
ATCO Electric		EUB							
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55	
EPCOR		EUB							
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55	
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55	
FortisBC Inc.	3/06; 11/07	BCUC	G-14-06; L-93-07	60.00	0.00	40.00	9.02	4.55	
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16	
Maritime Electric	1/08	IRAC	UE20937	57.31	0.00	42.69	10.00	na	
Newfoundland Power	12/07	NLPub	PU32 (2007)	54.01	1.15	44.84	8.95	4.60	1/
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na	2/
Northwest Territories Power Corp.	8/07	PUB of NWT	Decision 13-2007	52.26	0.00	48.59	9.25	4.60	3/
Ontario Electricity Distributors	12/06	OEB	Report of the Board	60.00	0.00	40.00	8.57	4.46	4/
Yukon Energy	10/05	YUB	OIC 1998/32; Order 2005-12, BCUC G-55-07	60.00	0.00	40.00	9.15	4.55	5/
Gas Distributors									
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55	
Enbridge Gas Distribution Inc	1/04; 1/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
Gaz Metropolitain	10/07	Régie	D-2007-116	54.00	7.50	38.50	9.05	4.78	
Pacific Northern Gas	11/07; 5/07	BCUC	L-93-07; G-55-07	56.20	3.80	40.00	9.27	4.55	
Terasen Gas	3/06; 11/07	BCUC	G-14-06; L-93-07	65.00	0.00	35.00	8.62	4.55	
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23	
Gas Pipelines									
Alberta Natural Gas	11/07; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.72	4.55	
Foothills Pipe Lines (Yukon) Ltd.	11/07; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.72	4.55	
TransCanada PipeLines	11/07; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.72	4.55	
Trans Quebec & Maritimes Pipeline	11/07	NEB	RH-2-94	70.00	0.00	30.00	8.72	4.55	
Westcoast Energy	11/07; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.72	4.55	

1/ The settlement agreement specifying ROE and capital structure was approved by the PUB.

2/ A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35% if approved.

3/ The capital structure of NTPC includes no cost capital (-.85%).

4/ The 8.57% ROE is for rates to be in effect as of May 2008. As per the 12/06 Report of the Board, the ROE is to be based on the January 2008 *Consensus Forecasts* and the January 2008 spread.

5/ The YUB set YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Utilities																			
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	1/	1/	1/	1/	1/	1/	9.40	9.60	9.50	8.93	8.51	8.75
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	na
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	1/	2/	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**
Gas Distributors																			
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	9.62	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**9.08**	**8.59**	**8.77**
Gas Pipelines (NEB)																			
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.07**	**8.66**	**8.78**

1/ Negotiated settlement, details not available.
2/ Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED RETURNS ON EQUITY FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.61	4.08
1991	13.56	9.72	3.84	12.51	8.14	4.37
1992	12.94	8.68	4.26	12.06	7.67	4.39
1993	12.16	7.86	4.30	11.37	6.59	4.78
1994	11.50	8.69	2.81	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.84	6.66	4.18	11.34	6.58	4.76
1998	10.15	5.59	4.56	11.59	5.54	6.05
1999	9.50	5.72	3.78	10.74	5.91	4.83
2000	9.79	5.71	4.08	11.41	5.88	5.53
2001	9.68	5.77	3.91	11.04	5.50	5.54
2002	9.62	5.67	3.95	11.10	5.41	5.69
2003	9.71	5.31	4.40	10.98	5.03	5.95
2004	9.59	5.11	4.48	10.73	5.08	5.65
2005	9.51	4.38	5.13	10.50	4.52	5.98
2006	9.07	4.33	4.74	10.39	4.93	5.46
2007	8.66	4.30	4.36	10.30	4.80	5.50
2008q1	8.78	4.10	4.68	10.37	4.35	6.02
Means:						
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.75**	**4.41**
1994-1998	**11.20**	**7.42**	**3.78**	**11.41**	**6.62**	**4.80**
1999-2007	**9.46**	**5.14**	**4.31**	**10.80**	**5.23**	**5.57**

[1/] 2008 ROE represents results for the full year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; www.federalreserve.gov; www.ustreas.gov.

YUB-YECL-34

Reference: Forecast income taxes, YECL Application, pages 1-5 - 1-6, Section 10 – Income Tax, page 10-1

The deferral accounts for which Yukon Electrical is seeking approval meet the standard criteria for the establishment of a deferral account:

(a) Costs are not under the control of the company and are not reasonably forecastable; or
(b) An error in forecasting could produce a loss or gain of a substantial magnitude.

The Board wants to better understand the request for a deferral account for income taxes.

Request:

(a) Please confirm the following calculations derived from the table on page 10-1

	Amount	Increase	Percentage Increase
2013	$248,000	$555,000	n/a
2014	$704,000	$456,000	184%
2015	$828,000	$124,000	18%

(b) YECL has forecast substantial increases in income taxes for the test period. Please discuss the factors that would lead to the increases noted above.

(c) Please provide additional detail on the position of YECL that income taxes require the use of deferral accounts.

Response:

(a) Confirmed.

(b) Yukon Electrical's utility earnings before tax are increasing for the test period primarily as a result of growth in rate base as well as amount of rate base being

financed by the shareholder. Depreciation expense, which is added back to utility earnings before tax for the purpose of calculating taxable income, is also significantly higher for the test period primarily as the result of the reinstatement of the provision for future removal and site restoration in depreciation rates.

(c) Yukon Electrical has not requested a deferral account for income taxes in this Application and does not believe such a deferral account is required.

YUB-YECL-56

Reference: Yukon economic activity, YECL Application, Section 2, pages 2-3

The latest economic projection from the Yukon Government, however, suggests a sharp slowdown in the pace of economic activity in 2012 and 2013. The Yukon Territory real Gross Domestic Product is estimated to have grown in the range of 2%-3% in 2012 and is expected to grow only 2% in 2013, down sharply from the 2011 growth rate of 6.5%. The Territory's unemployment rate rose to 6.9% in 2012, from 5.4% in 2011, and is projected to rise further, to 7.3%, in 2013. The Yukon Government also expects a slower population growth in 2013, dropping from 2.1% in 2012 to 1.3%. The value of building permits is estimated to have dropped 43% in 2012, compared to 2011. In its latest Northern Housing Report, Canada Mortgage and Housing Corporation forecast a 25% decrease in Whitehorse housing starts in 2012 as compared to 2011.

The projections were based on forecasts from Yukon Economic Review 2012, Yukon Economic Development (February 5, 2013), and Northern Housing Report, Canada Mortgage and Housing Corporation, 2012.

Request:

Please provide the Yukon Government's latest economic projection for 2012 and for each year of the test period.

Response:

Please refer to YUB-YECL-56 Attachment 1. An economic projection for 2014 and 2015 is not available.

Yukon Economic Review 2012

Whitehorse, Yukon
February 5, 2013

NOTE: The Yukon Economic Outlook 2012 was released on May 30, 2012. The review for 2012 contains information as recent as February 5, 2013. Updates to the May forecast document are highlighted in the shaded text boxes included at the end of each section.

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Highlights for 2011

Current as of May 30, 2012

- Preliminary estimates by Statistics Canada indicate that Yukon's real GDP grew 5.6% to $1.776 billion, from $1.681 billion in 2010. Gains in real GDP in 2011 marked the eighth consecutive year of growth.
- Yukon's average annual population increased by 1.6% in 2011 to 35,391. Increasing population in 2011 marked the eighth consecutive year of growth.
- Yukon's average unemployment rate of 5.4% for 2011 was down from 6.9% in 2010 and well below the national average of 7.5%.
- Mineral exploration expenditures in 2011 are estimated at nearly $307 million, topping the previous record high of $157 million in 2010.
- The value of Yukon mineral production for 2011 is estimated at $402 million, up from $299 million in 2010.
- Over 114,000 quartz claims were staked in Yukon in 2011, 38% higher than the previous record high of 83,161 recorded in 2010.
- In 2011, the Department of Tourism and Culture reported 309,863 visitors (border crossings), down slightly from 311,542 in 2010.
- The value of Yukon building permits in 2011 was a record $176.8 million, 34% higher than the $131.8 million reported for 2010.
- The value of retail sales in Yukon totaled a record $662 million in 2011, up 10.6% from $599 million in 2010.

Forecast for 2012

- Yukon's real GDP is expected to increase by 3% in 2012, with growth related primarily to increased mineral production.
- With labour force growth expected to outpace employment growth in 2012, the unemployment rate is expected to increase to 6.5%-7.0%.
- Yukon's population is forecast to average 36,000 in 2012, marking the ninth straight year of population growth.
- The value of mineral production is expected to total almost $600 million, up from the 2011 estimate of $402 million. Growth in 2012 is expected to stem primarily from higher production from the Wolverine mine, which declared commercial production in March 2012.
- Border crossings are expected to total about 313,000 in 2012, up slightly from approximately 310,000 in 2011.
- The value of building permits in 2012 is expected to be $150 million, down from the record $177 million in 2011, but well above the long-term average.
- Retail sales are expected to continue to benefit from a strong economy and total approximately $690 million in 2012, representing a 4% increase from 2011.

2012 Highlights – February 2013 Update:

- Current expectations are that real GDP growth in 2012 will be in the range of two to three per cent.
- The Yukon population in 2012 is now expected to average slightly less than the May forecast of 36,000.
- Yukon's labour market remained strong in 2012 with employment averaging 18,900 and the labour force averaging 20,400, a new record.
- The rate of growth in Yukon's labour force outpaced the growth of employment in 2012 which saw Yukon's unemployment rate increase to 6.9 per cent, up from 5.4 per cent in 2011.
- Annual average inflation for 2012 was 2.3 per cent, slightly below the May forecast of 2.5 per cent, and below the 3.0 per cent average of 2011.
- While exploration spending in 2012 will fall below the estimated record of over $300 million for 2011, interest in exploration in Yukon remains strong. Current expectations have exploration expenditures in 2012 at about $150 million, the third highest level on record.
- Benefitting primarily from higher production from the Wolverine mine, the value of Yukon's mineral production is expected to have grown for the seventh consecutive year in 2012, and total about $450 million, up from an estimated $402 million in 2011.
- Based on year-to-date border crossing data for 2012 annual tourist visitation is expected to have grown to about 321,000, 3.6 per cent higher than the 309,863 recorded in 2011 and well above the May 2012 forecast of 313,000.
- Building permit value for 2012 is estimated at $100.4 million, a decline of 43 per cent from 2011.
- Given the growth in retail sales posted in the first 11 months of 2012, the 2012 total will fall below the May forecast, but total over $675 million, up by over 2 per cent from $662.2 million in 2011.

Global, U.S. and Canadian Economic Outlook – 2011/2012

It was a year of significant uncertainty for the global economy in 2011. Fears of a second global economic downturn since 2008 persisted and were primarily related to worries about the difficult fiscal situations of some countries in the eurozone and the worry that potential defaults of some countries could have substantial impacts on the European banking system. This has had ramifications for global financial markets including decreased liquidity, the impacts of which have even been felt in Yukon. The performance of the U.S. economy also did little to ease global economic concerns in 2011, which has seen a recovery from the previous economic downturn that has been slower than many analysts expected. In addition, a number of Middle East countries saw internal conflicts, and in some cases changes in leadership that contributed to heightened geopolitical tension and concerns about interruptions in global economic oil supply. All of these events helped keep the price of oil high throughout 2011, likely dampening economic growth in some countries.

The most recent World Economic Outlook, published by the International Monetary Fund (IMF) in April 2012, estimates global economic growth of 3.9% for 2011.[1] Growth in 2011

[1] http://www.imf.org/external/pubs/ft/weo/2012/01/index.htm

was noted as lower than in 2010, where growth was estimated at 5.3%. As has been the case in recent years, growth rates in 'emerging and developing economies' in 2011 are estimated to have exceeded those of 'advanced economies' with overall growth for emerging countries estimated at 6.2%, almost four times the 1.6% growth noted for advanced economies. Leading the way for the emerging economies are China and India, which are estimated to have grown 9.2% and 7.2% respectively in 2011.

The World Economic Outlook (April 2012) includes global economic forecasts of 3.5% for 2012 and 4.1% for 2013, with growth in emerging and developing economies expected to be far more robust than growth in developed economies. Advanced economies are expected to post growth of 1.4% and 2.0% in 2012 and 2013 respectively. Emerging and developing countries are expected to post much higher growth with the IMF forecasting growth of 5.7% for 2012 and 6.0% for 2013. China and India, while expected to experience lower GDP growth than recorded in recent years, is expected to continue to fuel economic growth of emerging and developing countries in both 2012 and 2013. Strong domestic demand in these countries along with continuation of strong demand for oil resources from some of the other emerging and developing countries is expected to contribute to growth in the near-term.

The IMF (April 2012) is estimating economic growth of 1.7% for the United States for 2011, lower than the 3.0% growth estimate for 2010. Growth prospects for the U.S. are looking marginally better going forward with the IMF estimating growth of 2.1% for 2012 and 2.4% for 2013. Improving labour markets, higher consumer and business confidence, fiscal consolidation and generally improving household debt levels are all helping to improve the outlook for the U.S. economy. The conclusion of presidential elections in November should also help provide political certainty for the U.S.

Following estimated growth of 2.5% for 2011 for Canada, the IMF is projecting slightly weaker growth of 2.1% and 2.2% for 2012 and 2013 respectively. Canada's recent economic performance has been stable, with Canada generally outperforming most advanced economies. Canada's stable banking system, abundance of valued natural resources, as well as targeted monetary and fiscal stimulus have all contributed to Canada's continued economic growth. Going forward, the demand for Canadian oil and mineral resources is expected to remain strong, which will continue to contribute to Canada's economic growth prospects.

While global growth prospects have improved since late 2011, downside risks to growth remain. Even with the actions taken to address concerns of fiscal sustainability in some European countries the possibility of continued economic and fiscal troubles in Europe remains. Heightened concerns for defaults for some European countries could see investors move to pull resources out of the euro area which could have serious impacts on European and global growth prospects. Escalated unrest in a number of oil-producing countries could also place pressure on global oil prices, as fear of interruptions of global oil supply increases the risk premium on oil. A prolonged period of high oil prices would likely dampen global economic growth prospects, possibly stalling the recoveries of some advanced economies and placing downward pressure on emerging economies. Global growth prospects could also be impacted negatively if oil prices contribute to losses in consumer and business confidence and possible volatility on financial markets.

From a Canadian perspective, a number of areas could impact near-term growth. The Canadian dollar has had a prolonged period of strength versus the U.S. dollar, but further appreciation could have negative impacts on Canadian exports to the U.S. as a high dollar increases the relative costs of Canadian goods to American customers. Canadian exports could also be negatively impacted by a slowdown in the U.S. economic recovery, or lower demand from some European countries and parts of Asia.

In its most recent interest rate announcement on April 17, 2012, the Bank of Canada signaled that an increase in interest rates may be coming. The Bank, citing improving global economic prospects, noted that some modest withdrawal of monetary stimulus could become appropriate. With warnings from the Bank that many Canadians are carrying higher debt levels, an interest rate increase could have negative impacts on Canadian economic activity, as households face higher debt servicing costs. Ultimately the Bank's decision to raise interest rates will be dependent on a number of factors.

Further increases in oil prices may also impact Canadian households as increasing prices would reduce households' discretionary income, likely resulting in lower spending in certain areas of the economy. Higher oil prices could also impact the cost of manufacturing of a variety of goods, and also increase the costs of certain services, which could also have negative consequences for Canadian growth going forward.

Outlook for Global, U.S. and Canadian Economies

- The IMF's World Economic Outlook (April 2012) includes the following:
  - The global economy to grow by 3.5% in 2012 and 4.1% in 2013.
  - The U.S. economy to grow by 2.1% in 2012 and 2.4% in 2013.
  - The Canadian economy to grow by 2.1% in 2012 and 2.2% in 2013.

Global, U.S. and Canadian Outlook – February 2013 Update: While not insulated from the prevailing weakness in the global economy, strong fundamentals, including a stable banking system and abundant natural resources, has positioned Canada well to deal with the current economic headwinds.

The International Monetary Fund (IMF) reported in its January 2013 update to the *World Economic Outlook* that global economic growth is now expected to be 3.2 per cent for 2012 and 3.5 per cent for 2013. This follows estimated global economic growth of 3.9 per cent in 2011 and represents downward revisions from its October 2012 projections of 3.3 per cent growth for 2012 and 3.6 per cent growth for 2013.

The IMF's January update noted that policy actions have lowered risks in the euro area and the United States, but that the economic recovery in the euro area has been delayed. The IMF has indicated that global growth could exceed projections if "crisis risks do not materialize and financial conditions continue to improve" but that downside risks to the global economy, including setbacks in the euro area and excessive U.S. fiscal consolidation in the short term, remain significant.

For emerging and developing economies, the driver of global economic growth in recent years, growth is expected to be healthy, but below the growth levels recorded in 2010 and 2011. The IMF estimates growth of 5.1 per cent for 2012 and is projecting growth of 5.5 per cent growth for 2013. For China, the primary engine of growth in emerging markets in recent years, the IMF is estimating growth of 7.8 per cent in 2012 and forecasting growth of 8.2 per cent in 2013.

The IMF has revised down its near-term outlook for the euro area, with the euro area now expected to contract 0.2 per cent in 2013, down from the October 2012 forecast of 0.1 per cent growth. A contraction in 2013 would mark the second consecutive year of negative growth in the euro zone, following a 0.4 per cent contraction in 2012. The IMF noted that the euro area continues to pose a significant downside risk to global growth prospects.

The IMF's January 2013 projections for the U.S. have GDP growth of 2.3 per cent and 2.0 per cent for 2012 and 2013 respectively. These projections are broadly unchanged from the October outlook. Recent positive news on the U.S. employment front and signs of improvement in the U.S. housing market indicate that the U.S. economy is improving. A last minute deal to avoid automatic tax increases and mandatory spending cuts on January 1, 2013 was also good news for the U.S., and ultimately the global, economy. Going forward, performance of the U.S. economy will depend very much on the ability of policymakers to develop a plan to address the country's deficit issues and to deal with the issue of raising the federal debt ceiling during the first quarter of 2013. High consumer debt and uncertainty in the financial markets also remain a concern going forward.

The IMF's January update notes growth for Canada at 2.0 per cent and 1.8 per cent for 2012 and 2013, respectively. The current forecasts for Canada exceed the IMF's 2012 and 2013 forecasts for all Advanced Economies.

The Bank of Canada's January *Monetary Policy Report* noted growth of 1.9 per cent for 2012 and a forecast of 2.0 per cent for 2013. The Bank lowered growth estimates for both 2012 and 2013 noting that the slowdown in the second half of 2012 was more pronounced than anticipated. The Bank now expects the pace of economic growth in Canada to pick up through 2013 with the Canadian economy now expected to return to full capacity in the second half of 2014.

Yukon Outlook – Economic Sectors
Mining

Yukon's mining sector is in the midst of a strong period of growth with mining activity currently taking place in all areas of the mining life cycle. Current expectations for 2012 have Yukon's mining sector building on the recent strong performance, with the sector well-positioned to be a significant contributor to Yukon's economy for the foreseeable future.

There were over 100 companies doing exploration work in Yukon in 2011, with over 50 of these companies estimated to have spent in excess of $1 million each on exploration-related work. Natural Resources Canada's (NRCAN) Survey of Mineral Exploration, Deposit Appraisal & Mine Complex Development Expenditures indicates that exploration expenditures in 2011 totaled nearly $307 million, which is the highest value on record, and well above the $157 million estimated for 2010. Early indications are that 2012 mineral exploration spending will fall short of the record level reported for 2011, as concerns related to the global economy are making it difficult for mining companies to raise capital. This results in companies budgeting less for exploration-related activities. Current expectations are that mineral exploration expenditures could fall within $160-$200 million, which would be the second highest total on record, and would be well above the historic average.

Interest in Yukon's mineral potential is also being reflected in staking activity in recent years. In 2011, a record 114,587 new claims were staked, 38% higher than the high of 83,161 recorded in the previous year. Expectations for 2012 are that staking activity in the territory will fall well below the record level of 2011, but remain above the historic average.

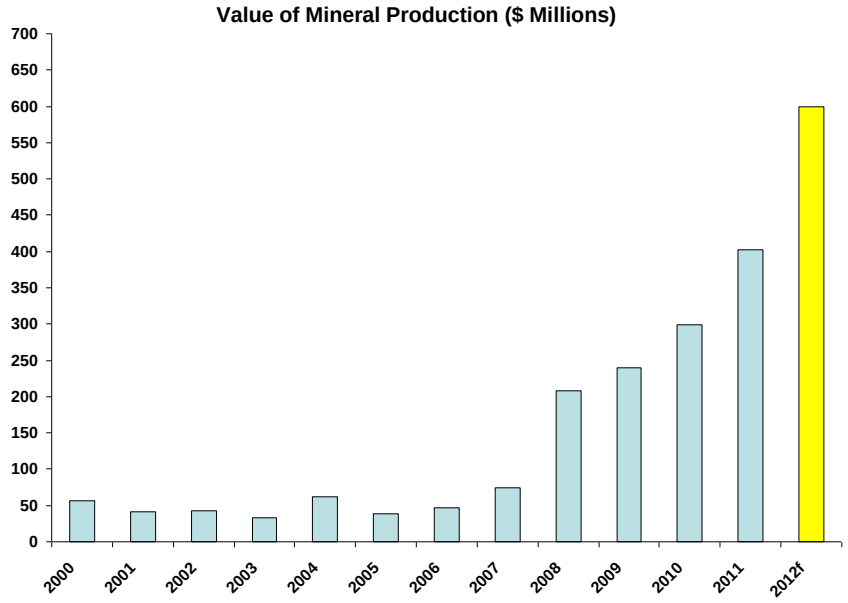
Driving much of the recent exploration activity has been strong growth in gold prices, which have doubled since 2007, and have shown tremendous gains in the last two years. It is estimated that exploration activities related to gold accounted for almost 70% of all mineral expenditures in 2011. With the expectation that gold prices will remain high for the foreseeable future, gold exploration will likely account for a significant portion of Yukon exploration activities going forward.

Following a period of strong development activity that has seen three mines developed and brought into production since 2005, development expenditures in 2012 are expected to fall below recent levels. Due primarily to development work associated with the Wolverine and Bellekeno mines, development expenditures in both 2010 and 2011 were estimated at about $150 million. With the vast majority of the development work associated with these projects now complete, development costs in 2012 will likely decline to less than half of the total seen in the last two years. Contributing to development expenditures in 2012 will be Capstone Mining Corp., which has budgeted over $32 million for capital expenditures on work related to the Minto mine, and Yukon Zinc Corp., which has budgeted $10-$15 million for continued work on the Wolverine project. Further expenditures could be seen on the Bellekeno project and the Victoria Gold project.

With Yukon Zinc Corp. filing Notice of Commencement of Production in March 2012, Yukon now has three commercially producing mines. Production from these mines, along with the production value of placer gold, is forecast to generate about $600 million in

mineral production value in 2012, far exceeding NRCAN's estimates of $402 million for 2011 and $299 million for 2010.[2] The additional mineral production in 2012 will be a significant contributor to Yukon's real GDP growth in 2012.

Placer gold production has been generally stable in recent years. Production in 2011 totaled 46,485 ounces; 9.4% lower than the 51,302 ounces produced in 2010. Current expectations for 2012 are for placer gold production to approach the 2010 level and total about 50,000 ounces.



Source: Natural Resources Canada; Department of Economic Development

Prices for minerals of interest to Yukon have generally been strong in recent years with annual gains in both 2010 and 2011 for gold, silver, copper, zinc and lead. The recent performance of gold and silver price in particular has been very strong. Gold prices in 2011 approached US$1,900 per ounce and averaged about US$1,570 per ounce for the year, 28% higher than the 2010 average of about US$1,225 per ounce. Silver prices in 2011 averaged over US$35 per ounce, up 74% from about US$20 per ounce in 2010.

While copper, zinc and lead prices have not surged like that of the prices for gold and silver, prices for all three of these metals have recorded recent gains.

- Copper prices averaged US$4.00 per pound in 2011, up 17% from US$3.42 per pound in 2010 and 71% from US$2.34 in 2009.
- Zinc prices averaged US$0.99 per pound in 2011, similar to the level recorded in 2010 and from US$0.75 per pound in 2009.
- Lead prices averaged US$1.09 per pound in 2011, up from US$0.97 per pound in 2010 and US$0.78 in 2009.

[2] NRCAN, 2011 Preliminary Estimate of Mineral Production http://mmsd.mms.nrcan.gc.ca/stat-stat/prod-prod/2011-eng.aspx

Continued economic uncertainty, especially in relation to the U.S. and some European countries, is expected to contribute to mixed performance for mineral prices in 2012. Gold and silver prices are expected to continue to perform well, with a number of forecasters expecting gains in price for both of these precious metals. Estimates for 2012 vary by forecaster. At the time of writing TD Economics was forecasting gold at US$1,766 per ounce and silver at US$35.02 per ounce, while BMO Capital Markets was forecasting gold at US$1,675 per ounce and silver at US$34.25 per ounce. Forecasters are less bullish on the prospects for copper, and zinc prices in 2012 with current expectations for prices to be steady, or slightly lower than the levels posted in 2011.

With three producing mines and a number of other projects advancing towards development decisions, the future of Yukon's mining sector looks promising. Currently there are six projects that have gone through permitting or in the process of obtaining the appropriate permits. There are also 10 projects that are doing advanced exploration or are completing feasibility-related work. A number of the project proponents have noted development timelines that could see development and production within five years.

While it is certainly the case that mining activities in Yukon are impacted by what is happening in the global economy and in the global mining sector, Yukon seems to be well-positioned to capitalize on the strong interest in its mineral resources. The expectation going forward is that development of Yukon's mineral sector will continue, with mining-related activity continuing to be an important contributor to Yukon's economy for the foreseeable future.

Outlook for Mining

- Mineral exploration spending in 2012 to fall in the $160-$200 million. This would be the second highest on record.
- With the vast majority of the development work associated with newly producing projects now complete, development costs in 2012 will likely decline to about half of the total seen in the last two years.
- The value of mineral production could total about $600 million in 2012, up from $402 million in 2011. Growth in 2012 is expected to stem primarily from a significant increase in production from the Wolverine mine which declared commercial production in March 2012.

Mining – February 2013 Update: While exploration spending in 2012 will fall below the estimated record of over $300 million for 2011, interest in exploration in Yukon remains strong. Current expectations have exploration expenditures in 2012 at about $150 million, the third highest level on record. In 2012, over 80 exploration projects were active in the territory, with over 30 of these spending at least $1 million.

Exploration for gold continues to account for the majority of recent exploration spending in Yukon. In 2012, exploration for gold accounted for 69 per cent of all exploration expenditures, well ahead of zinc-lead (11 per cent), silver (9 per cent), nickel-platinum (7 per cent) and copper (4 per cent). The price of gold, unlike those of the other commodities noted, recorded gains in 2012 with the price up 6.1 per cent, to almost US$1,670 per ounce.

In terms of staking activity, 2012 was more in line with staking activity seen prior to 2010. Claims staked in 2012 totaled fewer than 12,000, well below the over 114,000 claims staked in 2011.

Current estimates have development expenditures for 2012 near $100 million, down from an estimated $150 million in 2011, but above the May forecast for 2012 of $70 million.

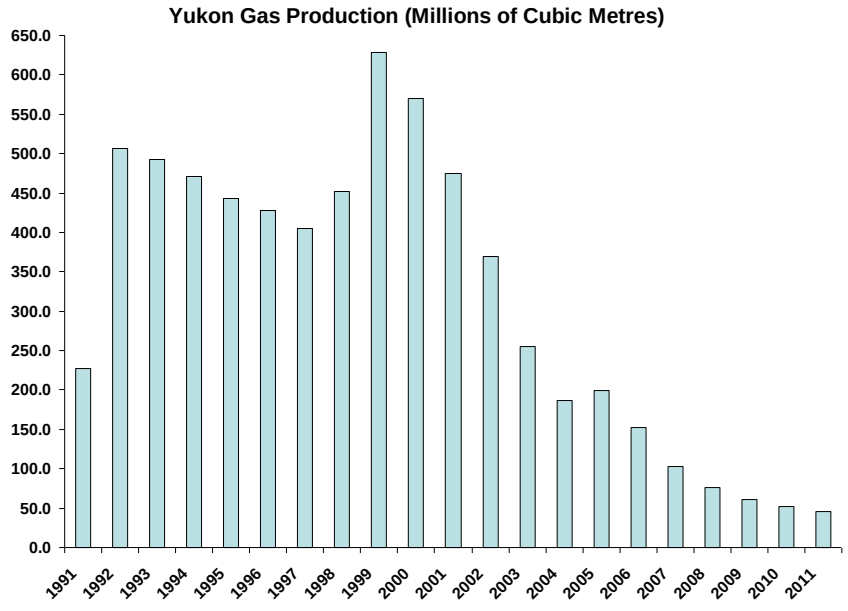
With the announcement of commercial production from the Wolverine mine in March 2012, Yukon now has three commercially producing mines. Benefitting primarily from higher production from the Wolverine mine, the value of Yukon's mineral production is expected to have grown for the seventh consecutive year in 2012, and total about $450 million, up from an estimated $402 million in 2011. While higher than 2011, the 2012 value of mineral production estimate is below the May 2012 forecast of $600 million. The downward revision is due to lower than expected production, as well as lower year-over-year prices for some minerals.

While, Yukon's mining sector has performed relatively well in 2012, the sector is not immune to global economic forces. Concerns of slowing growth in China, a sluggish U.S. recovery and ongoing economic turmoil in Europe has contributed to a volatile stock market and has seen many investors postpone their investment decisions, or decline to invest altogether. This weakened investment climate has contributed to lower exploration expenditures in 2012, as many junior mining companies found it difficult to raise funds to support exploration activities. With junior mining companies estimated to account for over 70 per cent of mining related spending in Yukon in every year for the period 2007 to 2012, current financing issues for junior mining companies is a concern for the local mining sector.

Even with the current global economic uncertainty, growth prospects for Yukon's mining sector are promising with six projects in permitting and a number at an advanced exploration or feasibility stage. For 2013, Alexco Resources has indicated that they are anticipating production from the Onek and Lucky Queen properties in 2013. Production from the Wolverine mine is also expected to increase in 2013 as the project achieves peak production. In terms of development, both Victoria Gold Corp. (Eagle Gold project) and Copper North Mining Corp. (Carmacks Copper project) have publically indicated a desire to begin development activities before the end of 2013.

Oil and Gas

Production at Kotaneelee, Yukon's only producing natural gas field, continued to decline in 2011 with production of 45.1 million cubic metres, down almost 13% from 51.6 million cubic metres in 2010. Kotaneelee has generally been on the decline since 1999, a normal trend for a field that is nearing the end of its productive life.



Source: Yukon Department of Energy, Mines & Resources

The Government of Yukon undertakes a disposition of oil and gas rights twice annually. The Spring 2012 Request for Postings (RFP) closed on January 18, 2012, and saw the Government of Yukon receive 12 RFPs for areas in southern Yukon in the Whitehorse Trough oil and gas basin. It was announced on April 12, 2012 that oil and gas exploration rights would not be issued in any of the 12 areas. This decision was made following the conclusion of a 60-day public review period and a technical review by the Government of Yukon.

For a number of years there has been discussion of the development of two proposed northern natural gas pipeline projects that if developed would have impacts on Yukon. Recent events seem to indicate that the development of either of these projects in the short-term is unlikely.

The Alaska Highway Pipeline Project would offer a source of natural gas to the United States' lower 48 states, with gas to be shipped via a 2,700-kilometre pipeline from Alaska, through Yukon and into Alberta. Recent development of shale gas resources in the United States has lessened the need for Alaskan natural gas and lowered the price of natural gas, and as such, alternative destinations for Alaskan gas are being considered. The project proponent, TransCanada PipeLines Limited, along with ExxonMobil, BP PLC, and ConocoPhillips, have committed to study the possibility of developing an alternative instate pipeline and liquefied natural gas (LNG) export plant. This project would be focused on production of LNG that would be targeted for Asian markets that have a growing demand

for natural gas products. Results of the evaluation of the LNG option for Alaskan gas will be important in determining if the Alaska Highway Pipeline Project will remain an option for development.

Development of the Mackenzie Gas Project in the near-term is uncertain. Abundant U.S. shale gas resources, natural gas prices at 10-year lows and cost escalations in the project itself were all noted as rationale for the recent announcement by the project lead, Imperial Oil, that the project had been put on hold and that budgets and staffing related to the project were being reduced. Beyond Imperial Oil, the partnership group that had been looking to develop the project includes Exxon Mobil Corp., ConnocoPhillips, Royal Dutch Shell PLC and the Aboriginal Pipeline Group. On April 2, 2012 the partnership issued a news release indicating that while the project was currently on hold, the project could be restarted if natural gas prices were to rebound sufficiently so as to improve the viability of the project.

There is optimism being generated about possible oil and natural gas development in Yukon coming out of the efforts of Northern Cross (Yukon) Limited to develop resources in the Eagle Plain area in northern Yukon. Development of natural gas resources would offer an opportunity for Yukon to reduce its dependency on the importation of petroleum products and provide a more cost-effective option to these petroleum products. With a substantial investment from CNOOC (China National Offshore Oil Corporation) International Inc., an affiliate of CNOOC Limited, one of China's largest independent oil and gas companies, Northern Cross has the capital to move forward with exploration work on its Yukon properties. Northern Cross has made a commitment of over $20 million for work on 15 exploration permits in the Eagle Plain area. Northern Cross is preparing a major exploration drilling program that is expected to begin in the summer of 2012, include the drilling of at least five wells and will likely last until the spring of 2013.

Economic growth in Yukon is increasing the demands for energy. Continued development of Yukon's mining sector in particular is placing additional pressure to identify adequate and cost-effective local sources of energy production. In response to these pressures the Department of Energy, Mines & Resources is examining the feasibility of developing Yukon's natural gas resources to meet Yukon's current and future energy demands.

Outlook for Oil and Gas

- Continue to evaluate the possibility of utilizing local gas resources to meet Yukon's current and future energy demands.

Oil & Gas - February 2013 Update: The Government of Yukon received two submissions to its most recent Oil and Gas Disposition Request for Postings which closed on January 16, 2013. Both request for oil and gas rights are for areas in the Eagle Plain basin. These requests are now subject to a 60 day public review period which is scheduled to close on March 28, 2013.

Production from the Kotaneelee gas field totaled 30.1 million cubic metres in 2012, down 33 per cent from 45.1 million cubic metres produced in 2011. In October 2012, EFL Overseas Inc. completed an acquisition of additional rights and interests in the Liard basin gas field and facilities in the Kotaneelee area from Nahanni Energy Inc. With the previous acquisition from Devon Canada EFL Overseas Inc. became the largest interest holder in the Kotaneelee with a general interest of 53.67 per cent and a working interest of 100 per cent in one gas well. EFL Overseas Inc. has indicated plans to pursue the acquisition of additional working interests in the Assets.

Northern Cross (Yukon) Limited continues to explore the development of resources in the Eagle Plain area in northern Yukon. Investment from CNOOC (China National Offshore Oil Corporation) International Inc., an affiliate of CNOOC Limited, one of China's largest independent oil and gas companies, has provided Northern Cross the capital to move forward with exploration work on its Eagle Plain properties. Northern Cross has made a commitment of over $20 million for work on 15 exploration permits and at the time of publication, two drill rigs were operational, with the expectation of 5-7 wells drilled by August 2013.

The Vuntut Gwitchin Development Corporation, on behalf of four northern First Nations, and with assistance from the Canadian Northern Economic Development Agency (CanNor), is also pursuing options to commercialize Eagle Plain gas. The feasibility study portion of the work has been completed and the four First Nations are now moving into the business planning portion of the project.

Yukon Energy Corporation is also assessing the use of natural gas to meet its short term (five year) generation requirements and as a transition fuel as it develops longer term renewable energy projects.

Tourism

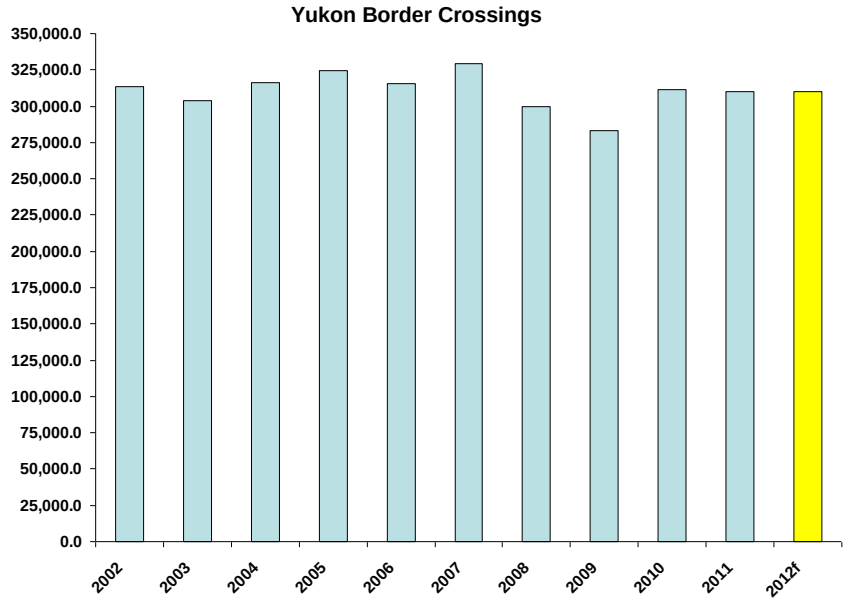
Recent tourism activity in Yukon has been steady, with annual international border crossings totaling about 310,000 in the past two years. Annual international border crossings of 309,863 were recorded in 2011, down slightly from 311,542 in 2010, but still above the almost 283,000 recorded for 2009.

Visitation via motorcoach totaled 122,205 in 2011, up 5.7% from 2010. Countering some of the gains in motorcoach visitation was a decline in visitation via private vehicle, which decreased 4.2% to 187,658. Higher year-over-year prices for fuel likely account for some of the decline in private vehicle traffic in 2011.

Recent shifts in visitation origin are consistent with what is being seen nationally, and is reflective of the current economic reality which is seeing advanced economies post weaker growth rates than those of emerging economies such as China or India.

Data for visitation by place of origin indicates that visitation from the U.S., Yukon's largest tourism market, was down 3.5% compared to the previous year, totaling 206,271 in 2011. While 2011 saw over 7,500 fewer visits from the U.S., visitation from the U.S. still accounted for two-thirds of all border crossings in 2011.

Non-U.S. visitation in 2011 increased to 103,592, up 6.0% from 2010. Increases in non-U.S. visitation were seen in all areas with visitation from other parts of Canada increasing 7.5% to 26,812 and foreign visitation increasing 5.1% to 33,329. Driving the foreign visitation was a strong increase in Asia/Pacific tourists, up 14.5% to 11,892.



Source: Yukon Department of Tourism & Culture; Yukon Department of Economic Development

At the Erik Nielsen Whitehorse International Airport, the total number of passengers arriving and departing increased by 7.7%, or 19,140 for a total of 267,442. The total for 2011 exceeded the previous high recorded in 2010, and it is the third consecutive year of increasing passenger volumes at the airport, potentially indicating a shift in how visitors will travel to the territory in the future.[3]

Given Yukon's well-established and unique tourism product, the outlook for visitation to Yukon remains generally positive. With that said, there are factors that have the potential to negatively impact visitation in the near-term.

The Canadian dollar has experienced a prolonged period of strength which is continuing into 2012. The Canadian dollar has been especially strong against the U.S. dollar, with the Canadian dollar averaging US$0.9997 year-to-date (to May 25, 2012). A strong Canadian

[3] Department of Tourism, Yukon Visitor Statistics, Year-End Report 2011

dollar increases the relative cost of travel to Canadian destinations, which could act as a deterrent to individuals who might travel to Yukon. A strong Canadian dollar could also impact visitation from other parts of Canada, as Canadians look to take advantage of a strong currency and travel to U.S. destinations or other regions where the Canadian dollar has appreciated against the local currency.

Economic and political uncertainty in the U.S. and abroad could also have some negative ramifications for travel to Yukon going forward. It has been a turbulent time for a number of countries with many countries' economies struggling in light of ongoing global economic concerns. Weakness in the economic recoveries of some countries, especially the U.S., could influence the global recovery and could negatively impact tourism. Continued economic and political uncertainty will likely cast a shadow on travel prospects going forward, which could have impacts on visitation to Yukon in the near-term.

Travel in 2012 could also be negatively impacted by high and increasing oil prices. Oil prices to May 25, 2012 averaged US$101.83 per barrel, 2.8% higher than in the same period of 2011. High oil prices are being reflected in higher gasoline prices as well with average year-to-date (to May 22, 2012) gasoline prices in Whitehorse are up 3.1% from the same period in 2011 to almost $1.31 per litre. Higher fuel prices increase the costs of operating a motor vehicle and also the operational costs for airlines. Given that the primary modes of transportation into Yukon are motor vehicles and aircraft, it is possible higher fuel prices and the subsequent higher costs of travel, could impact visitation to Yukon.

While risk factors exist, current expectations have visitation in 2012 being up slightly, with a forecast of 313,000 border crossings in 2012.

Outlook for Tourism

- Border crossings are expected to total about 313,000 in 2012, up slightly from approximately 310,000 in 2011.

Tourism – February 2013 Update: Data provided by the Department of Tourism & Culture has border crossings in the first ten months of 2012 at 315,440, up 3.8 per cent (11,517 visitors), versus the same period in 2011.

By mode of transportation increases in the January to October period were recorded in motorcoach visitation, up 9.9 per cent (12,067 visitors). Visitation via personal vehicle was down 550, representing a slight decline versus the first ten months of 2011.

By country of origin, the largest percentage increase in visitation was recorded from the United States which grew 4.9 per cent (9,881 visitors). Growth was also recorded in visitation from other parts of Canada, up 3.8 per cent (1,018 visitors) and foreign visitation, up 1.8 per cent (601 visitors). Visitation attributed to Yukon residents was on par with the same period of 2011 (up by 17 visitors).

U.S. visitation remains the largest contributor to Yukon visitation, accounting for over 67 per cent of all border crossings in the first ten months of 2012. After a decline of 3.5 per cent in 2011, U.S. visitation has rebounded well so far in 2012. Gains in 2012 may be a reflection of an improved economic situation for many U.S. residents, as the U.S. economy continues to recover from the recent global economic downturn.

The Department of Tourism & Culture has indicated that border crossings are expected to have grown to about 321,000 in 2012, 3.6 per cent higher than the 309,863 recorded in 2011 and well above the May 2012 forecast of 313,000.

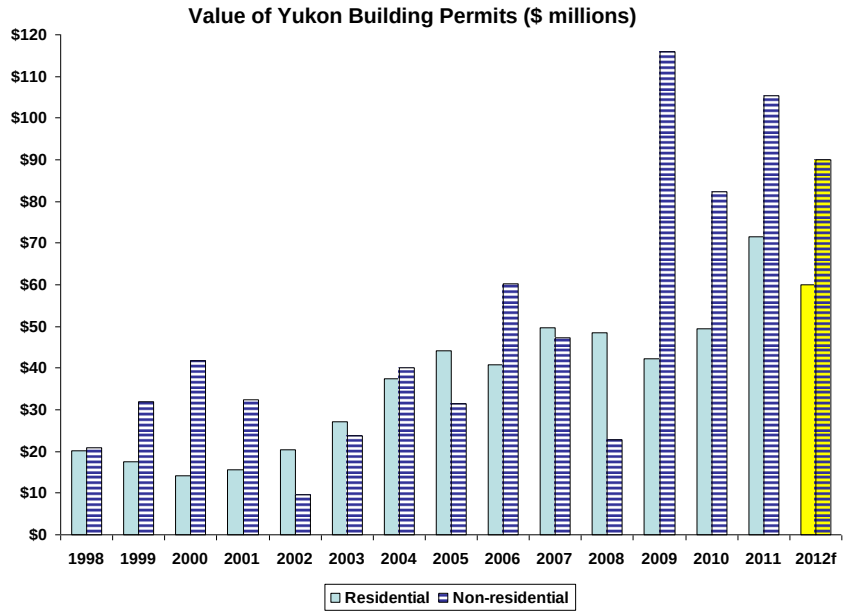
Beyond 2012, current expectations are for Yukon's tourism sector to continue to perform well. Assuming that the U.S. economy continues to recover and that the global economy does not fall into recession, visitation in 2013 is expected to total about 328,000 (Department of Tourism and Culture).

Construction

Reflecting the strong performance of Yukon's economy, a record value of building permits of $176.8 million were recorded in 2011. The 2011 value was over 34% higher than the $131.8 million reported for 2010. Gains in building permit value in 2011 stemmed primarily from growth in the value of residential building permits and institutional building permits.

Residential permit value reached $71.5 million in 2011, up almost 45% from the $49.4 million recorded in 2010. Strong residential construction in Whitehorse was the primary driver of residential permit value in 2011, with Whitehorse accounting for over $52 million in residential building permits.

The value of institutional permits totaled $70.8 million in 2011, up almost 50% from the $47.3 million posted in 2010. Major institutional projects such as the Watson Lake and Dawson City hospitals, development of a new wastewater treatment facility and district heating system in Dawson City, and water treatment facilities in Carcross and Ross River all contributed to strong growth in institutional permit value in 2011.



Source: Yukon Bureau of Statistics; Yukon Department of Economic Development

The expectation for 2012 is for construction activity to remain strong, with residential and institutional construction expected to once again be the primary drivers of permit value.

The most recent Government of Yukon budget included a significant commitment of funding in 2012-2013 to address land availability and housing needs. Of the almost $35 million noted to be directed towards these efforts, about half will be related to development of the Whistle Bend sub-division. Lots from phase one of the six phase project are scheduled to be ready for purchase by the fall of 2012 and will provide 93 single family, eight duplex and nine multi-family lots, along with one commercial and one school site. Upon completion, the Whistle Bend sub-division is expected to include 3,900 housing units and accommodate close to 8,000 people.

Beyond Whistle Bend, residential spending in 2012 will include the development of more Government of Yukon land in the downtown Whitehorse area, work related to the Grizzly Valley sub-division near Whitehorse and development of residential lots in Mayo and Watson Lake.

The Government of Yukon's 2012-2013 budget also included over $51 million in various transportation infrastructure projects. Included among these projects are:

- $15 million under the Shakwak project for the Haines Road and North Alaska Highway and a further $1 million from the Government of Yukon for the North Alaska Highway;
- Over $7 million for reconstruction of the Campbell Highway from km 10 to 190 and a further $1.5 million for surfacing;
- Over $7 million over the next two years to extend water and sewer services to the south commercial area at the Erik Nielson Whitehorse International Airport;

- $6 million for work related to rehabilitation and improvement of the Upper Liard Bridge;
- $2.6 million for reconstruction, Bituminous Surface Treatments and re-vegetation work on the Atlin Road;
- $2 million for reconstruction of the Takhini Hotsprings road;
- Over $1.8 million for improvement projects for the Erik Nielson Whitehorse International Airport including taxiway improvements, rehabilitation and the installation of a second bridge or jet way; and
- Over $1.8 million to address airside deficiencies at Yukon aerodromes outside Whitehorse.

In addition to transportation infrastructure and residential development the 2012-2013 Government of Yukon budget included funding commitments in a variety of other areas:

- $15 million under the Building Canada Plan for the construction of new wells, pump houses and treatment plants to improve the quality of drinking water in Burwash Landing, Carcross, Deep Creek, Dawson City, Haines Junction, Mendenhall, Old Crow, Ross River, Tagish and Teslin;
- Over $12 million under the Building Canada Plan as part of a multi-year program to improve water and wastewater systems in Faro, Haines Junction, Mayo and Watson Lake;
- Over $7 million for a new Emergency Response Centre in Whitehorse that will serve as the city's primary ambulance station;
- $7 million to construct a new recreation centre in Ross River;
- Over $4 million to develop a second-stage housing facility in Whitehorse;
- $3 million under the Canada Strategic Infrastructure Fund to complete the last phase of the Whitehorse Waterfront Development project;
- Over $2.3 million to build the Arrest Processing Unit, which will serve as a replacement for the RCMP detachment cells and offer prisoners access to 24-hour nursing and specially trained correctional staff; and
- Almost $1.3 million for replacement of the F.H. Collins Secondary School in Whitehorse.

The City of Whitehorse's most recent capital budget, released in December 2011, also notes several capital projects which will see notable spending in 2012. Most prominent among the spending included in the capital budget is $6.5 million in 2012 that is allocated for the extension of water and sewer services and associated road work in the Marwell area. New fire hydrants will also be added in some parts of Marwell to enhance fire protection. The city's most recent capital budget also includes 2012 expenditures of $4 million for expansion of the Porter Creek Reservoir and $3.8 million for reconstruction of Black Street, including work on roads, sidewalks and water and sewer lines. The budget also includes a total of $4.1 million to be directed towards the replacement of the Selkirk Pumphouse, a facility that currently handles Whitehorse's entire water supply. Of the $4.1 million, $2 million is planned to be spent in 2012 with the remaining $2.1 million to be spent in 2013.

Activity related to the mining sector should also continue to contribute to construction activity in Yukon. Even with the vast majority of the development work associated with Yukon's three commercially producing mining projects complete, these projects will continue to have expenditures associated with ongoing mine development. Capstone Mining Corp. has budgeted over $32 million for capital expenditures on work related to the Minto mine. Yukon Zinc Corp has also budgeted $10-$15 million for continued work on the Wolverine project. Further expenditures could be seen on the Bellekeno project as well as on the Victoria Gold project if development were to commence in the fourth quarter of 2012.

The current forecast for the value of building permits issued for 2012 is $150 million, which would be down from the record $177 million recorded in 2011, but above the long-term average.

Outlook for Construction

- The value of building permits in 2012 is expected to be $150 million, down from the record $177 million in 2011 but above the long-term average.

Construction - February 2013 Update: The forecast completed in May 2012 was for building permits in 2012 to total $150 million, down 15.2 per cent from the $176.8 million recorded in 2011. The expectation was for residential and institutional construction to be the primary contributors to total permit value in 2012

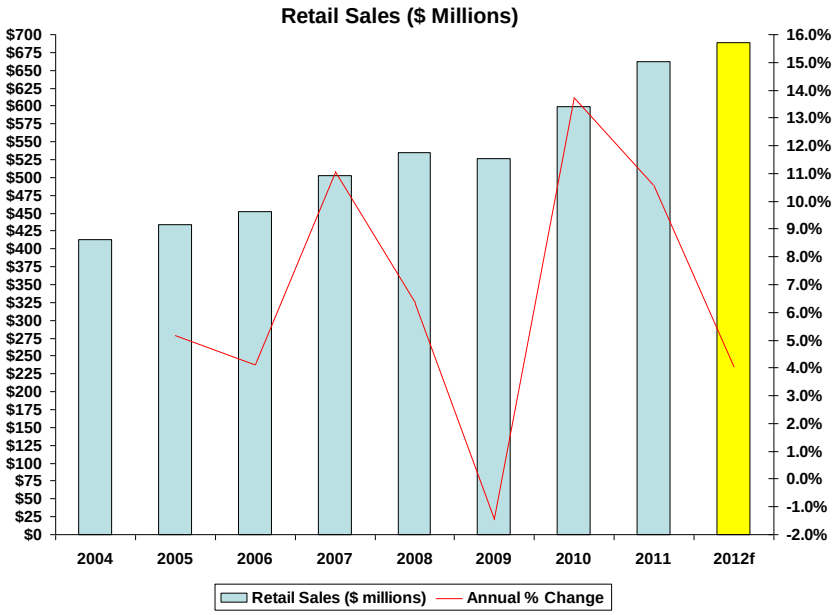
Data for 2012 indicate that building permit value fell well short of the May forecast. Total building permit value totaled $100.4 million in 2012, down 43.2 per cent from the $176.7 million recorded in 2011. While total building permit value was down, residential permit value was strong, totaling $65.7 million in 2012, accounting for over 65 per cent of total building permit value.

Declines in 2012 were noted in all areas of building permits, with lower value of government and institutional building permits accounting for the majority of the difference in total building permit value. After averaging almost $68 million in the three years prior to 2012, government and institutional permits totaled under $21 million in 2012, down 71.5 per cent from the $70.7 million recorded in 2012. Lower government and institutional permits account for 66 per cent of the total decline in total building permits of $76.3 million.

Going forward expenditures related to the reclamation of the Faro mine, further development of existing mines and spending related to new mining startups are expected to contribute to construction activity. Further expenditures related to residential construction, in particular related to the Whistle Bend subdivision in Whitehorse, as well as construction of the F.H. Collins School, is also expected to contribute to construction activity in the near-term.

Trade

The value of retail sales in Yukon totaled a record $662 million in 2011, up 10.6% from $599 million in 2010. Strong economic activity related to mining development, increased employment, higher population and higher year-over-year fuel prices are all considered contributing factors to retail sales growth in 2011.



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Department of Economic Development

The value of retail sales for 'other retail stores' exceeded $400 million in 2011, up from $378.7 million in 2010. Contributing to the higher value of sales were higher year-over-year fuel prices, which positively impacted the value of sales from gasoline stations.

Increases in sales were also recorded in other retail sale categories in 2011. Sales from 'food and beverage stores' increased 4.4% to $195.7 million in 2011, up from $187.5 million in 2010. Sales from 'clothing and clothing accessories stores' also increased 5.9% to $18.4 million in 2011, up from $17.4 million in 2010.

Strong oil prices are expected to continue to impact fuel prices in 2012 and will likely continue to impact the value of retail sales. Year-to-date (to May 25, 2012) oil prices have averaged almost US$102 per barrel, 2.8% higher than in the same period in 2011. Higher oil prices are contributing to higher fuel prices with year-to-date (to May 22, 2012) gasoline prices in Whitehorse 3.1% higher than the same time in 2010. Fuel prices are expected to post a year-over-year increase in 2012, which could see costs of shipping goods to Whitehorse increase as a result of the higher fuel costs. If passed onto consumers, higher fuel costs could also positively impact retail sales.

Rising fuel prices are not expected to be the only driver of retail sales in 2012. Continued economic growth, stemming primarily from activities related to the mining sector could also positively impact retail sales in 2012. A growing population, increases in the number of people employed and higher household incomes should all contribute to growth in retail sales in 2012.

Overall, it is expected that retail sales will grow to approximately $690 million in 2012.

Outlook for Retail Sales

- Retail sales are expected to continue to benefit from a strong local economy and total approximately $690 million in 2012, representing a 4% increase from 2011.

Trade – February 2013 Update: Retail sales in the first eleven months of 2012 totaled almost $617 million, up 2.5 per cent from $602 million recorded in the same period in 2011.

Food and Beverage Stores, the largest segment of retail sales in Yukon at about 30 per cent of total sales, is reported to have increased by 2.5 per cent in the first eleven months of 2012 when compared to the same period in 2011. Strong growth in sales was recorded by Gasoline Stations; which recorded gains of 10.7 per cent. Sales from Gasoline Stations accounted for over 16 per cent of all sales in the first eleven months of 2012. Growth was also recorded in Food and Beverage Stores (2.5 per cent) and Health and Personal Care Stores (3.0 per cent).

Declines in 2012 were noted in Clothing and Clothing Accessories Stores and Building Material and Garden Equipment and Supplies Dealers which fell 7.0 per cent and 0.9 per cent respectively. Sales from these two categories together accounted for over 10 per cent of total sales in the first eleven months of 2012.

Given year-to-date growth in retail sales, the 2012 total will fall below the May forecast, but total over $675 million, up by over 2 per cent from $662.2 million in 2011.

Looking forward to 2013, expectations for continued economic growth are expected to contribute to further gains in retail activity with sales anticipated to approach $700 million.

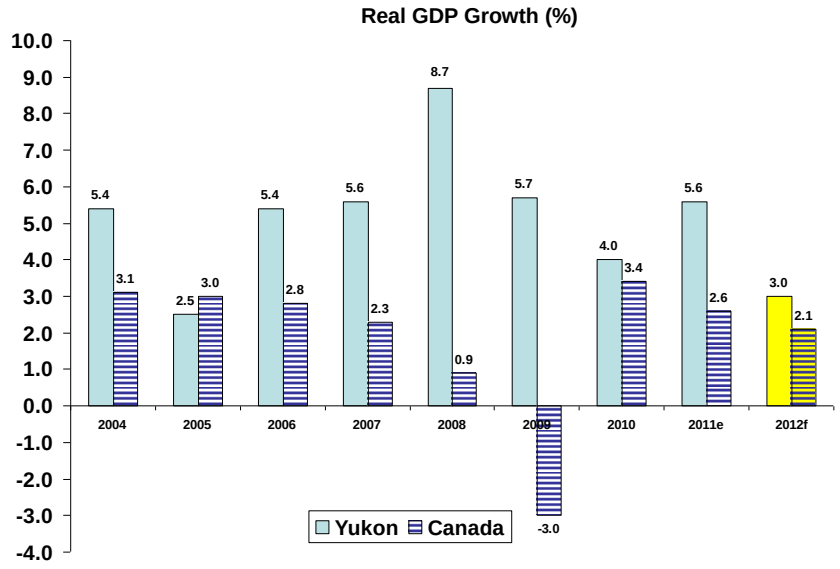
Yukon Outlook – Economic Indicators

Economic Growth (Gross Domestic Product)

On April 27, 2012, Statistics Canada released preliminary 2011 real GDP data by industry for provinces and territories. It is estimated that Yukon's real GDP in 2011 totaled $1.776 billion, up 5.6% from $1.681 billion in 2010. Yukon's estimated growth for 2011 was more than double the national growth rate of 2.6% and ranked second among all Canadian jurisdictions, behind only Nunavut at an estimated growth rate of 7.7%. With estimated growth of 5.2%, Alberta posted the strongest growth among all the provinces.

Statistics Canada attributed Yukon's 2011 real GDP growth primarily to activities related to Yukon's growing mining sector. It was noted that gains in output of support activities to mining and oil and gas extraction, record levels of mineral exploration and higher mineral production due to the opening of the Bellekeno mine were all contributing factors to real GDP growth in 2011. Statistics Canada also highlighted a 21% growth in construction output, a 6.6% growth in retail trade and a 4.7% growth in the finance, insurance and real estate sector as contributing to overall growth in Yukon's 2011 real GDP.

With growth in 2011, Yukon has posted eight consecutive years of real GDP growth, with Yukon's growth rate exceeded the national average in seven of the eight years.



Source: Yukon Bureau of Statistics; Statistics Canada; International Monetary Fund; Yukon Department of Economic Development

The development of Yukon's mining sector has been the primary driver of real GDP growth in recent years, with Yukon's economy benefitting from expenditures related to mineral exploration and development and the addition of mineral production from new mining projects. Significant construction activity in Yukon has also contributed to economic growth in recent years.

The expectation for 2012 is that Yukon will post gains in real GDP for the ninth consecutive year as mining and construction related activities continue to contribute to Yukon's economy. The current forecast for 2012 real GDP is for growth of upwards of 3%. The addition of commercial mineral production from the Wolverine mine, supported by continued construction activity and tourism-related activity, is expected to contribute to real GDP growth in 2012.

The Conference Board of Canada's latest economic forecast for the three Canadian territories was released in March 2012.[4] The current Yukon forecast is for 2.9% Real GDP growth for 2012. The Conference Board of Canada releases economic forecasts for the three territories twice annually and a revision to the March estimate is expected this summer.

Outlook for GDP

- Yukon's real GDP is expected to increase by upwards of 3% in 2012, with growth related primarily to increased mineral production.

[4] *Territorial Outlook, Winter 2012*, Conference Board of Canada, Centre for the North

Gross Domestic Product - February 2013 Update: Statistics Canada's revised estimates for real GDP for the provinces and territories, released on November 19, 2012, indicate that Yukon's real GDP grew 6.5 per cent in 2011 to $2.407 billion*. Yukon's growth estimate for 2011 was more than double the national growth rate of 2.6 per cent and the highest growth rate of any Canadian jurisdiction.

Statistics Canada noted a number of areas that helped contribute to the strong growth in 2011. A 22.0 per cent increase in Yukon exports, more than double the pace of growth in 2010, was a strong contributor to growth in 2011. Due to the strength of outlays on mineral exploration business investment in Yukon rose 6.5 per cent in 2011 which also contributed to real GDP gains. An increase of 4.5 per cent in Consumer spending was the strongest growth in the country, a reflection of higher household spending on services, in particular rents, air transportation and food and non-alcoholic beverage services.

The December 14, 2012 Statistics Canada real GDP by industry release also noted a gain of 6.5 per cent in Yukon's real GDP. Gains in Mining, Quarrying and Oil and Gas Extraction was the primary contributor to total real GDP growth in 2011, accounting for over 80 per cent of all estimated gains in 2011.

In May 2012 the Department of Economic Development forecasted growth upwards of 3 per cent in 2012. Current expectations are that real GDP growth in 2012 will likely be in the range of 2 to 3 per cent.

The Conference Board of Canada's Territorial Outlook Summer 2012 publication includes a forecast of 3.7 per cent for Yukon real GDP for 2011.

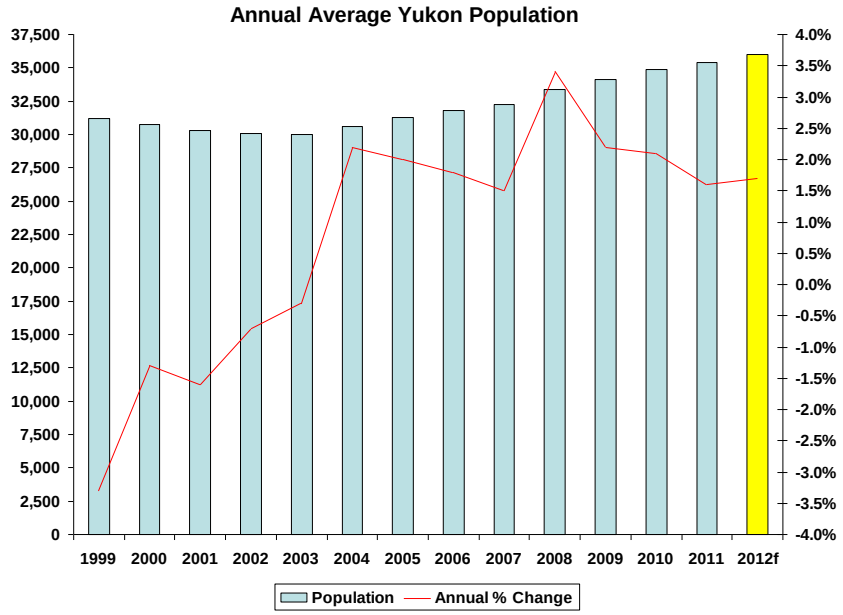
Early expectations for 2013 are for Yukon's real GDP to grow for a tenth consecutive year, but likely below levels recorded in recent years. Uncertainty related to the level of construction activity, mining project development, and exploration expenditures are tempering initial growth expectations for 2013.

*Periodically, the provincial and territorial economic accounts undergo historical revisions, which are much broader in scope than the regular annual revisions. These revisions are reserved for incorporating updated international national accounting standards, as well as conceptual, classification, presentational and major statistical changes. Statistics Canada's November 2012 release included revisions back to 2007, with further revisions back to 1981 to be released in 2013. Real dollar figures are now expressed in 2007 dollars, versus the previous 2002 dollars.

Population

Yukon's annual average population grew by 544 to 35,391 in 2011, representing a 1.6% increase over the previous year. This is the eighth straight year of population growth for Yukon and marks the highest annual average population since the beginning of the Yukon Census.[5]

[5] Accurate population estimates for the gold rush era are not available. However, the first census population estimate for Yukon was conducted in 1901 when the population was recorded at 27,219.



Source: Yukon Bureau of Statistics; Yukon Department of Health & Social Services; Yukon Department of Economic Development

Comparing December 2011 to December 2010, Yukon's population grew 1,133 to 35,800, an increase of 3.3%. Growth was concentrated in Whitehorse where the population increased by 886 (3.4%) to 27,190. The population of Whitehorse accounts for over 75% of Yukon's total population.

Over the same period, population growth was recorded in fourteen communities, with declines only in Watson Lake (-15) and Tagish (-1). The population of Burwash Landing was unchanged. Outside of Whitehorse the largest increases in population were recorded in Dawson City, Marsh Lake and Carmacks, which posted population gains of 78, 42 and 35, respectively.

Yukon's demographic situation is similar to the national story with both the populations of Yukon and Canada generally getting older. The population of mid-to-retirement aged Yukoners, aged 45-64, totaled 11,499 in December 2011, 1.7% higher than the December 2010 total. Accounting for over 32% of Yukon's total population in December 2011, the 45-64 segment of Yukon's population has exceeded 30% of the total population for seven consecutive years.

The number of post-retirement age residents (65 and older) has also been increasing in recent years. As of December 2011, 3,291 Yukon residents were 65 or older, accounting for over 9% of Yukon's total population. Only ten years ago, this segment of the population accounted for only about 6% of the population, with only 1,850 post-retirement age people living in Yukon.

While it is the case that Yukon has an aging population, the number of individuals 19 years of age or younger actually increased to 7,748 in December 2011, up from 7,604 in December

2010. This marked the first such increase since 2004. Optimism related to a strong local economy could account for the increase, as young people and young families may be looking to capitalize on employment and business opportunities in the territory.

Optimism related to a generally healthy economy could also explain the continued growth in Yukon's 'working age' population (15-64). This segment of the population totaled 26,887 in December 2011, up 2.8% from December 2010. More than half (13,261) of the 'working age' population falls within the ages of 20-44, with this segment of the population posting strong growth in the last two years, with annual increases of over 4.5% in both 2011 and 2010. Notable increases in 2011 were also recorded in the 25-29 range (7.6%) and the 30-34 range (6.8%).

On average, the population of Yukon is expected to total 36,000 in 2012, representing a 1.7% increase over 2011 and marking the ninth straight year of population increase.

Outlook for Population

- Yukon's average population is forecast to increase to 36,000 in 2012, marking the ninth straight year of population growth.

Population - February 2013 Update: Revised population estimates by the Yukon Bureau of Statistics show Yukon's average annual population in 2011was 35,246, an increase of 1.1 per cent over 34,847 in 2010. This was a downward revision from the 2011 annual average reported in the May Outlook of 35,391, and down from a preliminary annual average increase of 1.6 per cent.

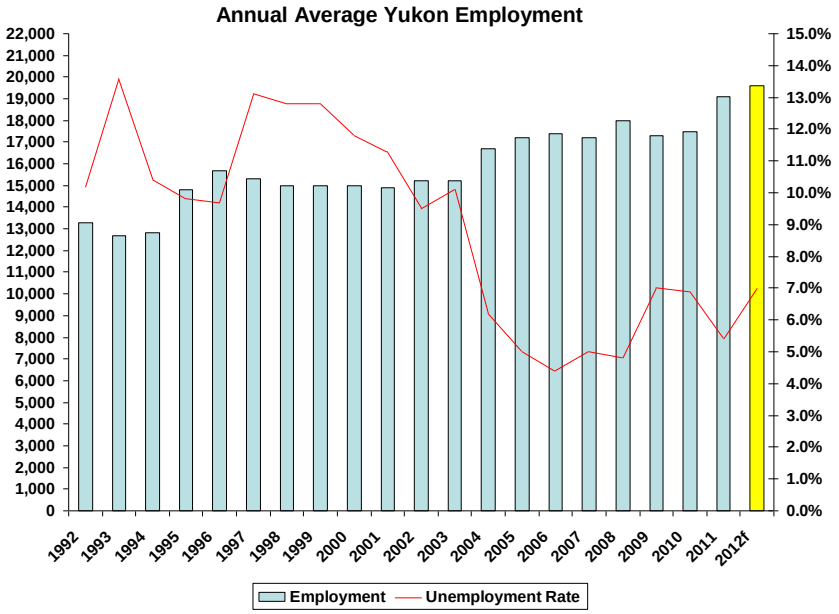
Yukon's average population to June 2012 is estimated at 35,723, an increase of 1.4 per cent over the revised 2011 average. Working age population data from the Yukon Labour Force Survey indicate continued population growth in the second half of the year.

The Yukon population in 2012 is now expected to average just short of the May forecast of 36,000. Early expectations for 2013 are for further gains, with the population expected to grow to an average of approximately 36,500.

Labour Force

The Yukon Labour Force Survey, as conducted by Statistics Canada, reported the average Yukon labour force at 20,200 in 2011, almost 7% higher than the figure reported for 2010. The average number of employed in Yukon was 19,100, up 9.1% from the 2010 average of 17,500. The survey also reported the average number of unemployed in 2011 at 1,100, down over 15% from 2010.

The average Yukon unemployment rate was reported as 5.4% for 2011, down from 6.9% in 2010. The 2011 unemployment rate for Yukon was amongst the lowest in the country and well below the national average of 7.5%.[6]



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Labour Force Survey

Yukon Labour Force Survey data for the first four months of 2012 notes across-the-board increases for key labour force statistics. From January to April, Yukon's labour force has averaged 20,600, 4.4% higher than in the same period of 2011. The average number of people employed in the first four months of 2012 was 19,150, up 375 from the same period of 2011. Gains have also been noted in the number of people unemployed and the unemployment rate in the first four months of 2012, with the average number of unemployed increasing by 525 to 1,450 and the unemployment rate increasing from an average of 4.7% in the first four months of 2011 to an average of 7% in the first four months of 2012.

The higher unemployment rate in early 2012 appears to be at odds with the recent performance of other key economic indicators, as Yukon continues to experience continued high levels of mining-related activity, retail trade and construction activity. Recent increases in the unemployment rate could be attributable to the relatively small sample size used for the Yukon Labour Force Survey, which can often be subject to volatility. Yukon's labour force has also seen significant recent growth, which is often the case for an economy that is performing well. Recent labour force growth outperforming recent employment gains has also contributed to an increase in the unemployment rate in recent months.

[6] Methodological differences exist between the Labour Force Survey used for the Territories and that of the Labour Force Survey utilized for the Provinces. Sample design, rotation pattern and reliability criteria are different in the three territories from those in the ten provinces.

Generally, Yukon's economic fundamentals appear to be strong and the expectation is that continued economic growth driven by continued high levels of construction and resource sector activity should contribute to lower unemployment rates in the coming months. The forecast for 2012 has Yukon's average labour force increasing from 20,200 to 21,000, an increase of 4%. Yukon employment is also anticipated to post growth in 2012, with the current forecast for an increase of just over 2.5% to 19,600. The number of unemployed is expected to increase to 1,400 in 2012, up from 1,100 in 2011. With labour force growth expected to outpace growth in employment, the average unemployment rate for 2012 is expected to increase to 6.5%-7.0%.

Outlook for Labour Force

- Yukon's labour force is expected to continue to post gains in 2012, with the labour force expected to grow to a record 21,000. The number of people employed is also expected to increase to a record 19,600.
- With labour force growth expected to outpace employment growth in 2012, the unemployment rate is expected to increase to 6.5%-7.0%.
- Opportunities associated with resource development activities and high levels of construction activity will continue to support employment gains in 2012.

Labour Force - February 2013 Update: Following a record average of 19,100 employed in 2011, Yukon's average employment in 2012 fell to 18,900. While down from 2011, Yukon employment in 2012 recorded the second highest level in history. Yukon's labour force averaged a new record in 2012, growing to 20,400, up from the previous record of 20,200 in 2011.

With a growing labour force and a slight decline in average employment, 2012 saw Yukon's unemployment rate increase to an average of 6.9 per cent, up from 5.4 per cent in 2011.

Further economic growth is expected to support gains in both employment and the labour force in 2013. Current expectations have employment growing to 19,100 and the labour force growing to 20,600.

Consumer Prices

The Whitehorse Consumer Price Index (CPI)[7] for 2011 increased by 3.0%, higher than the 0.8% increase recorded in 2010. The 3.0% annual increase in the Whitehorse CPI is the second highest increase since 1992, and followed two years of very low inflation in 2009 and 2010. Looking at national performance, Canada's CPI increased by a similar 2.9% in 2011.

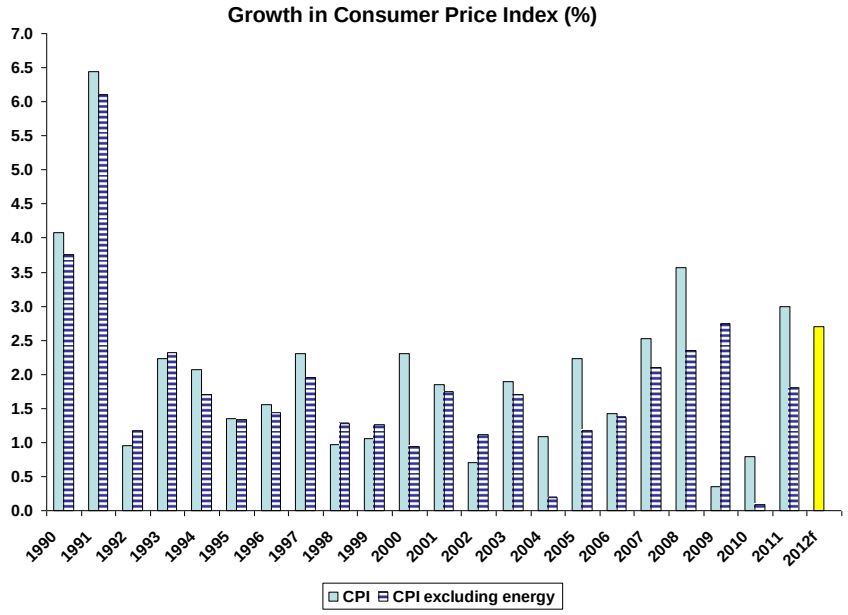
Contributing to Whitehorse's CPI growth in 2011 was the persistence of strong prices for crude oil, which contributed to higher fuel prices at the consumer level. Comparing 2011 to 2010, the price of Home Heating Fuel Oils and other oils is reported to have increased by 21% and the price of Gasoline over the same period is reported to have increased by 15%.

[7] Consumer Price Index data is only available in Yukon for Whitehorse.

The Energy component of Whitehorse CPI increased by over 13% in 2011, partly a reflection of higher crude oil prices.

Looking at the various components of CPI for Whitehorse, only Clothing and Footwear (down 0.9%) did not post an increase in 2011. On a percentage basis, the largest increases were seen in Gasoline (14.7%), Transportation (5.0%) and Shelter (4.4%). All these components were impacted by higher oil and fuel prices, contributing to much of the increases noted for these components in 2011.

Other components of CPI that saw increases in 2011 included Food (2.6%), Alcoholic Beverages & Tobacco Products(2.3%), Household Operations, Furnishings & Equipment (0.9%), Health & Personal Care (0.6%) and Recreation, Education & Reading (0.1%).



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Department of Economic Development

Expectations for 2012 are that prices will continue to be impacted by high and increasing fuel prices. Year-to-date (to May 25, 2012) oil prices have averaged almost $102 per barrel, almost 3% higher than the $99 per barrel averaged in the same period of 2011. Many forecasters are expecting oil prices to remain high throughout 2012, with BMO Capital Markets Economics forecasting oil to average $100 per barrel and TD Economics calling for oil to average just over $100 per barrel.

The impacts of higher year-over-year prices for fuel have been reflected in Whitehorse's average CPI in the first four months of 2012, which has increased 2.7% versus the same period in 2011. The Gasoline component of Whitehorse's CPI was up 4.7% in the first four months of 2012, while the overall Energy component increased by 5.5%.

The current forecast from the Department of Economic Development is for Whitehorse CPI to increase 2.5% in 2012. This forecast represents the expectation that oil prices will likely continue to be strong throughout 2012, contributing to year-over-year growth in fuel costs. Higher fuel prices could lead to price increases in other areas as increased fuel prices trickle through the economy and increase costs.

Outlook for the Consumer Price Index

- Inflation in Whitehorse in 2012 is expected to average 2.5%, slightly lower than the 3.0% recorded in 2011.

Consumer Prices - February 2013 Update: Consumer inflation averaged 2.3 per cent in Whitehorse in 2012, slightly below the May 2012 forecast of 2.5 per cent and below the 3.0 per cent average observed for all of 2011.

Energy continues to be a key driver of inflation in Whitehorse, with the 2012 average up 3.9 per cent over the 2011 average. Fuel oil has been reported as increasing by 4.5 per cent in this period and electricity has increased by 4.1 per cent.

In addition, the gasoline component of the Consumer Price index is reported to have increased by 3.6 per cent over 2011 figures. Gains in 2012 have also been reported in Shelter and Food which have increased 3.4 per cent and 2.6 per cent respectively.

Looking forward to 2013, national forecasts are predicting a slowing of inflation over the year with a slowing housing market but increases in food prices. It expected that inflation should average 2.0 per cent overall in Whitehorse in 2013, slightly higher than the national average.

Key Economic Indicators Summary Table

Indicator	*2011*	*2012f*	*2012f update*	*2013pf*
Population, Prices, Rates				
Population	35,246	36,000	36,000 (f)	36,500
Inflation Rate^	3.0%	2.5%	2.3%	2.0%
Overnight Rate	1.00%	1.00%	1.00%	1.00%
Canada/U.S. Exchange Rate	$1.012	$1.010	$1.001	$1.009
Employment†				
Labour Force	20,200	21,000	20,400	20,600
Employment	19,100	19,600	18,900	19,100
Unemployed	1,100	1,400	1,400	1,500
Unemployment Rate	5.4%	6.5%-7.0%	6.9%	7.3%
Economic Output				
Real Gross Domestic Product (millions of chained 2007 dollars)	$2,407 (r)	$2,480	$2,455-$2,480 (f)	$2,510
Real GDP Growth Rate	6.5%	3.0%	2.0-3.0% (f)	2.0%
Commodity Prices~				
Gold ($US/oz)	$1,570	$1,675	$1,668	$1,708
Silver ($US/oz)	$35.11	$34.25	$31.15	$31.83
Zinc ($US/lb)	$0.99	$0.95	$0.88	$0.95
Copper ($US/lb)	$4.00	$3.85	$3.61	$3.61
Oil - WTI ($US/bbl)	$95.08	$100	$94.20	$94.00
Natural Gas ($US/MMBTU) NYMEX	$4.00	$2.15	$2.75	$3.60
Mining				
Value of Mineral Production	$401.8 million (p)	$600 million	$450 million (f)	$550-$600 million
Exploration Expenditures	$331.7 million (r)	$160-$200 million	$150 million (f)	--
Development Expenditures	$150 million (e)	$70 million	$98 million (f)	--
Oil and Gas				
Natural Gas Prod'n Volume - m3	45,143,100	--	30,131,300	--
Construction				
Permitted Building Construction	$176.8 million	$150 million	$100.4 million	$125 million
Trade				
Value of Retail Sales	$662.2 million	$690 million	$675 million (f)	$690-$700 million
Tourism				
Non-resident Border Crossings+	309,863	313,000	321,000 (f)	328,000

f = forecast, pf = preliminary forecast, e = estimate, p = preliminary estimate, r = revised, -- = not available
^ CPI increase for Whitehorse only
† annual averages – totals may not total due to rounding
~ annual averages
+ as reported by the Department of Tourism & Culture

Data Sources for Key Economic Indicators Summary Table

Indicator	*Source*
Population	Yukon Bureau of Statistics, Yukon Population Estimates, Yukon Department of Economic Development
Inflation (Consumer Price Index)	Statistics Canada, Consumer Price Index, Yukon Department of Economic Development
Overnight Rate	Bank of Canada (average daily rate), BMO Capital Markets
Canada/U.S. Exchange Rate	Bank of Canada (average daily noon rate), BMO Capital Markets
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Economic Development
Economic Output (GDP)	Statistics Canada, Provincial Economic Accounts , Yukon Department of Economic Development
Commodity Prices	BMO Capital Markets
Value of Mineral Production	Natural Resources Canada Minerals and Mining Statistics Division, Yukon Department of Economic Development
Mineral Exploration Expenditures	Natural Resources Canada Minerals and Mining Statistics Division , Yukon Department of Economic Development
Mine Development Expenditures	Yukon Department of Energy, Mines & Resources, Yukon Department of Economic Development
Natural Gas Production Volume	Yukon Department of Mines & Energy
Tourism Visitation	Yukon Department of Tourism & Culture, Yukon Department of Economic Development
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Economic Development
Retail Trade	Statistics Canada, Yukon Department of Economic Development

YUB-YECL-57

Reference: Demand-side management impacts beyond 2013, YECL Application, page 2-5

The increase in UPC relating to electric space heating, however, is not expected to be extended beyond 2013, as it is expected to be offset by a reduction in consumption due to the demand side management program. Attachments 1 to 21 show the historical data as well as the regression results.

Request:

Please provide the excel spreadsheet(s) with all formulas intact for Attachments 2 to 21, of Section 2 in the application.

Response:

Please refer to YUB-YECL-57 Attachments 1 to 21.

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1334.11	1165.70	1,295	
Feb-98	1071.75	719.10	1,134	
Mar-98	1027.75	756.60	1,043	
Apr-98	902.89	458.60	921	
May-98	787.72	270.60	815	
Jun-98	696.64	119.50	719	
Jul-98	627.52	111.60	628	
Aug-98	604.15	189.20	592	
Sep-98	706.17	327.80	699	
Oct-98	780.59	557.70	772	
Nov-98	922.54	792.30	936	
Dec-98	970.68	1051.80	927	
Jan-99	1383.18	1183.10	1,334	
Feb-99	1164.46	976.40	1,088	
Mar-99	1040.97	734.00	1,069	
Apr-99	944.37	508.80	936	
May-99	811.83	391.90	774	
Jun-99	754.75	153.90	758	
Jul-99	646.43	108.60	649	
Aug-99	610.64	145.70	621	
Sep-99	697.48	311.20	700	
Oct-99	763.70	499.80	786	
Nov-99	881.73	792.50	895	
Dec-99	994.21	844.00	1,062	
Jan-00	1264.66	1082.90	1,270	
Feb-00	1036.07	735.20	1,090	
Mar-00	918.53	659.20	986	
Apr-00	854.15	515.60	842	
May-00	846.79	382.00	815	
Jun-00	731.77	172.50	725	
Jul-00	656.21	142.10	641	
Aug-00	620.05	219.90	591	
Sep-00	733.99	354.20	713	
Oct-00	787.21	539.20	788	
Nov-00	884.41	691.20	952	
Dec-00	940.26	977.80	936	
Jan-01	1185.33	722.70	1,384	
Feb-01	938.26	864.10	922	
Mar-01	987.72	765.30	998	
Apr-01	867.85	506.80	860	
May-01	816.38	390.40	780	
Jun-01	763.40	167.30	760	
Jul-01	657.29	139.60	643	
Aug-01	598.61	139.60	613	
Sep-01	660.89	309.00	664	
Oct-01	754.64	573.40	737	
Nov-01	904.51	818.00	904	
Dec-01	1056.40	1094.60	989	
Jan-02	1223.01	935.60	1,307	
Feb-02	1013.30	824.60	1,019	
Mar-02	997.99	921.10	925	
Apr-02	990.09	653.30	904	
May-02	798.77	361.60	777	
Jun-02	707.08	175.60	699	
Jul-02	642.71	130.90	633	
Aug-02	648.08	182.80	639	
Sep-02	680.33	314.40	681	
Oct-02	758.56	444.30	811	
Nov-02	873.29	582.60	999	
Dec-02	898.43	845.20	966	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1202.44	989.10	1,258	
Feb-03	995.15	756.60	1,037	
Mar-03	985.34	834.50	959	
Apr-03	892.59	514.30	881	
May-03	790.52	363.70	768	
Jun-03	749.45	192.80	732	
Jul-03	657.75	84.40	673	
Aug-03	617.42	180.60	609	
Sep-03	709.08	359.20	685	
Oct-03	726.71	466.70	767	
Nov-03	910.68	874.60	880	
Dec-03	1072.98	911.60	1,104	
Jan-04	1245.81	1257.90	1,157	
Feb-04	1092.27	697.20	1,166	
Mar-04	923.71	753.50	941	
Apr-04	948.79	466.60	963	
May-04	751.60	272.50	778	
Jun-04	711.26	83.70	753	
Jul-04	667.46	74.20	688	
Aug-04	607.29	101.70	642	
Sep-04	669.67	367.50	642	
Oct-04	761.52	540.50	762	
Nov-04	897.87	719.80	950	
Dec-04	1015.36	899.50	1,053	
Jan-05	1277.77	1165.80	1,238	
Feb-05	1107.70	795.20	1,129	
Mar-05	922.86	613.70	1,015	
Apr-05	906.16	453.30	928	
May-05	734.86	256.60	770	
Jun-05	705.13	154.40	709	
Jul-05	660.11	132.60	650	
Aug-05	621.38	150.80	629	
Sep-05	741.98	299.30	751	
Oct-05	733.74	534.60	737	
Nov-05	921.61	762.60	951	
Dec-05	967.23	794.40	1,062	
Jan-06	1196.53	1096.20	1,195	
Feb-06	1043.82	821.30	1,051	
Mar-06	1072.57	906.30	1,007	
Apr-06	933.65	519.10	920	
May-06	801.77	346.90	788	
Jun-06	726.49	173.10	720	
Jul-06	704.17	118.40	701	
Aug-06	635.06	201.60	616	
Sep-06	736.28	295.70	747	
Oct-06	795.22	520.50	806	
Nov-06	938.75	1162.20	753	
Dec-06	1130.58	824.30	1,209	
Jan-07	1245.66	912.00	1,343	
Feb-07	1050.91	998.80	962	
Mar-07	1139.27	954.20	1,048	
Apr-07	985.39	511.90	975	
May-07	735.33	322.10	735	
Jun-07	719.79	140.50	731	
Jul-07	702.49	102.30	708	
Aug-07	597.33	154.20	604	
Sep-07	688.79	308.40	692	
Oct-07	754.77	543.70	753	
Nov-07	922.64	724.60	972	
Dec-07	995.15	1069.50	942	

Yukon Electrical Company Limited
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Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	
Jan-08	1298.44	1113.80	1,287		
Feb-08	1185.79	954.60	1,121		
Mar-08	1011.53	734.70	1,039		
Apr-08	942.12	517.30	929		
May-08	788.52	307.90	796		
Jun-08	696.47	225.60	662		
Jul-08	680.93	173.40	648		
Aug-08	700.97	187.70	689		
Sep-08	700.67	318.70	699		
Oct-08	732.64	563.00	721		
Nov-08	984.81	782.50	1,003		
Dec-08	1011.40	1186.20	895		
Jan-09	1528.55	1137.90	1,504		
Feb-09	1122.38	955.40	1,057		
Mar-09	1093.54	868.50	1,049		
Apr-09	945.55	515.20	934		
May-09	773.10	331.20	768		
Jun-09	704.15	144.10	713		
Jul-09	702.59	62.50	730		
Aug-09	627.45	158.30	632		
Sep-09	719.71	306.10	725		
Oct-09	771.84	541.80	771		
Nov-09	953.63	781.50	973		
Dec-09	1013.21	943.40	1,027	10882.60	
Jan-10	1345.94	991.10	1,401		
Feb-10	1012.55	679.20	1,096		
Mar-10	940.25	656.00	1,010		
Apr-10	944.91	461.20	962		
May-10	795.15	292.00	811		
Jun-10	719.19	171.90	713		
Jul-10	685.61	117.30	683		
Aug-10	627.66	146.20	638		
Sep-10	720.70	332.40	711		
Oct-10	821.83	520.40	833		
Nov-10	904.24	717.60	958		
Dec-10	1057.11	1162.50	953	10770.18	
Jan-11	1436.52	1010.20	1,481		
Feb-11	1129.49	905.60	1,091		
Mar-11	1256.14	901.70	1,193		
Apr-11	955.17	511.20	945		
May-11	892.99	296.20	907		
Jun-11	743.84	161.00	744		
Jul-11	677.48	127.80	670		
Aug-11	647.93	217.90	620		
Sep-11	737.64	328.50	731		
Nov-11	831.75	513.30	847		
Nov-11	943.59	936.25	879		
Dec-11	1136.92	775.10	1,242	11349.30	
Jan-12	1356.98	1118.10	1,343		
Feb-12	1170.51	707.50	1,239		
Mar-12	1098.22	756.20	1,114		
Apr-12	930.47	450.60	953		
May-12	835.03	350.80	820		
Jun-12	770.21	200.00	749		
Jul-12	708.91	140.10	694		
Aug-12	677.42	157.90	682		
Sep-12	695.14	287.15	710		
Oct-12	802.64	631.40	754		
Nov-12	1011.59	969.60	929		
Dec-12	1262.76	1196.80	1,141	11128.22	0.7%
2013-F				11,211	
2014-F				11,211	
2015-F				11,211	

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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1347.45	1165.70	1,299	
Feb-98	914.75	719.10	991	
Mar-98	850.95	756.60	870	
Apr-98	789.18	458.60	812	
May-98	794.14	270.60	828	
Jun-98	547.08	119.50	574	
Jul-98	607.13	111.60	608	
Aug-98	705.26	189.20	690	
Sep-98	667.56	327.80	659	
Oct-98	891.67	557.70	881	
Nov-98	847.85	792.30	864	
Dec-98	981.34	1051.80	927	
Jan-99	1435.13	1183.10	1,375	
Feb-99	997.18	976.40	903	
Mar-99	878.46	734.00	912	
Apr-99	933.28	508.80	923	
May-99	735.24	391.90	689	
Jun-99	592.75	153.90	597	
Jul-99	714.33	108.60	717	
Aug-99	570.63	145.70	584	
Sep-99	733.56	311.20	736	
Oct-99	848.54	499.80	876	
Nov-99	918.66	792.50	935	
Dec-99	943.63	844.00	1,027	
Jan-00	1393.34	1082.90	1,400	
Feb-00	907.58	735.20	973	
Mar-00	833.03	659.20	916	
Apr-00	818.24	515.60	803	
May-00	807.82	382.00	768	
Jun-00	726.05	172.50	718	
Jul-00	615.67	142.10	596	
Aug-00	625.23	219.90	589	
Sep-00	855.11	354.20	829	
Oct-00	808.86	539.20	810	
Nov-00	886.88	691.20	970	
Dec-00	1094.80	977.80	1,090	
Jan-01	975.84	722.70	1,220	
Feb-01	930.14	864.10	911	
Mar-01	1077.80	765.30	1,091	
Apr-01	775.11	506.80	766	
May-01	690.34	390.40	645	
Jun-01	697.52	167.30	693	
Jul-01	566.74	139.60	549	
Aug-01	566.46	139.60	584	
Sep-01	743.86	309.00	748	
Oct-01	726.03	573.40	705	
Nov-01	998.62	818.00	998	
Dec-01	885.26	1094.60	803	
Jan-02	1218.64	935.60	1,322	
Feb-02	1166.34	824.60	1,173	
Mar-02	942.27	921.10	852	
Apr-02	853.02	653.30	747	
May-02	811.69	361.60	786	
Jun-02	552.24	175.60	542	
Jul-02	580.09	130.90	568	
Aug-02	712.11	182.80	701	
Sep-02	638.11	314.40	639	
Oct-02	895.99	444.30	960	
Nov-02	783.30	582.60	938	
Dec-02	999.16	845.20	1,082	

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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1066.96	989.10	1,135	
Feb-03	944.33	756.60	996	
Mar-03	886.30	834.50	854	
Apr-03	896.61	514.30	883	
May-03	751.25	363.70	724	
Jun-03	555.79	192.80	535	
Jul-03	678.53	84.40	697	
Aug-03	595.25	180.60	586	
Sep-03	714.57	359.20	685	
Oct-03	849.90	466.70	899	
Nov-03	923.64	874.60	886	
Dec-03	1239.55	911.60	1,278	
Jan-04	1229.48	1257.90	1,120	
Feb-04	942.57	697.20	1,033	
Mar-04	928.19	753.50	949	
Apr-04	949.09	466.60	967	
May-04	638.54	272.50	671	
Jun-04	552.23	83.70	603	
Jul-04	655.59	74.20	681	
Aug-04	501.23	101.70	544	
Sep-04	788.19	367.50	754	
Oct-04	803.27	540.50	804	
Nov-04	860.77	719.80	925	
Dec-04	950.08	899.50	997	
Jan-05	1479.20	1165.80	1,431	
Feb-05	1034.01	795.20	1,060	
Mar-05	842.04	613.70	956	
Apr-05	955.29	453.30	982	
May-05	665.59	256.60	709	
Jun-05	684.41	154.40	689	
Jul-05	550.42	132.60	537	
Aug-05	592.88	150.80	603	
Sep-05	760.75	299.30	771	
Oct-05	774.90	534.60	779	
Nov-05	949.64	762.60	986	
Dec-05	919.10	794.40	1,035	
Jan-06	1402.18	1096.20	1,400	
Feb-06	980.19	821.30	989	
Mar-06	1262.81	906.30	1,183	
Apr-06	805.13	519.10	788	
May-06	688.68	346.90	672	
Jun-06	697.69	173.10	690	
Jul-06	640.63	118.40	637	
Aug-06	515.05	201.60	491	
Sep-06	742.30	295.70	755	
Oct-06	749.73	520.50	763	
Nov-06	1006.36	1162.20	778	
Dec-06	1107.96	824.30	1,204	
Jan-07	1554.07	912.00	1,673	
Feb-07	1054.99	998.80	946	
Mar-07	1221.11	954.20	1,109	
Apr-07	858.23	511.90	846	
May-07	656.87	322.10	657	
Jun-07	728.49	140.50	742	
Jul-07	590.23	102.30	597	
Aug-07	647.66	154.20	655	
Sep-07	654.75	308.40	659	
Oct-07	762.75	543.70	761	
Nov-07	1083.25	724.60	1,144	
Dec-07	918.94	1069.50	853	

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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1321.82	1113.80	1,308	
Feb-08	1748.89	954.60	1,669	
Mar-08	1140.23	734.70	1,174	
Apr-08	873.47	517.30	857	
May-08	829.73	307.90	839	
Jun-08	709.60	225.60	667	
Jul-08	522.26	173.40	482	
Aug-08	686.98	187.70	673	
Sep-08	753.10	318.70	751	
Oct-08	824.86	563.00	810	
Nov-08	1161.51	782.50	1,184	
Dec-08	1092.15	1186.20	949	
Jan-09	1569.02	1137.90	1,539	
Feb-09	1236.09	955.40	1,156	
Mar-09	1113.31	868.50	1,058	
Apr-09	996.41	515.20	982	
May-09	612.07	331.20	606	
Jun-09	571.72	144.10	583	
Jul-09	666.52	62.50	700	
Aug-09	598.19	158.30	603	
Sep-09	822.17	306.10	828	
Oct-09	812.98	541.80	813	
Nov-09	1007.46	781.50	1,031	
Dec-09	1085.22	943.40	1,103	
Jan-10	1623.07	991.10	1,690	
Feb-10	1029.40	679.20	1,132	
Mar-10	1034.68	656.00	1,120	
Apr-10	1023.38	461.20	1,044	
May-10	800.29	292.00	820	
Jun-10	565.81	171.90	558	
Jul-10	716.77	117.30	714	
Aug-10	673.16	146.20	686	
Sep-10	737.70	332.40	726	
Oct-10	867.23	520.40	881	
Nov-10	964.21	717.60	1,030	
Dec-10	1074.83	1162.50	947	11350.25
Jan-11	1619.00	1010.20	1,673	
Feb-11	1314.80	905.60	1,268	
Mar-11	1226.65	901.70	1,150	
Apr-11	914.05	511.20	902	
May-11	879.91	296.20	897	
Jun-11	597.78	161.00	598	
Jul-11	678.05	127.80	668	
Aug-11	693.54	217.90	659	
Sep-11	842.89	328.50	834	
Nov-11	835.82	513.30	854	
Nov-11	1102.99	936.25	1,024	
Dec-11	1062.36	775.10	1,191	11718.47
Jan-12	1703.03	1118.10	1,686	
Feb-12	1190.91	707.50	1,275	
Mar-12	1449.90	756.20	1,469	
Apr-12	690.39	450.60	718	
May-12	804.25	350.80	785	
Jun-12	756.31	200.00	730	
Jul-12	563.98	140.10	546	
Aug-12	758.98	157.90	764	
Sep-12	658.70	287.15	677	
Oct-12	801.33	631.40	742	
Nov-12	1382.24	969.60	1,281	
Dec-12	1290.39	1196.80	1,140	11814.86
2013-F				11,627.9
2014-F				11,627.9
2015-F				11,627.9

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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	795.40	1165.70	772	
Feb-98	784.90	719.10	822	
Mar-98	698.47	756.60	708	
Apr-98	607.38	458.60	619	
May-98	582.92	270.60	600	
Jun-98	472.72	119.50	486	
Jul-98	428.20	111.60	429	
Aug-98	436.56	189.20	429	
Sep-98	459.85	327.80	456	
Oct-98	499.13	557.70	494	
Nov-98	571.22	792.30	579	
Dec-98	584.94	1051.80	558	
Jan-99	838.31	1183.10	809	
Feb-99	727.77	976.40	682	
Mar-99	692.78	734.00	709	
Apr-99	606.91	508.80	602	
May-99	609.42	391.90	587	
Jun-99	501.14	153.90	503	
Jul-99	488.61	108.60	490	
Aug-99	412.25	145.70	419	
Sep-99	434.53	311.20	436	
Oct-99	540.51	499.80	554	
Nov-99	526.58	792.50	535	
Dec-99	790.71	844.00	831	
Jan-00	557.88	1082.90	561	
Feb-00	695.40	735.20	728	
Mar-00	576.79	659.20	618	
Apr-00	587.76	515.60	580	
May-00	525.67	382.00	506	
Jun-00	488.19	172.50	484	
Jul-00	448.25	142.10	439	
Aug-00	391.01	219.90	374	
Sep-00	500.13	354.20	488	
Oct-00	455.07	539.20	456	
Nov-00	503.14	691.20	544	
Dec-00	630.92	977.80	628	
Jan-01	635.82	722.70	756	
Feb-01	556.01	864.10	546	
Mar-01	674.24	765.30	681	
Apr-01	531.79	506.80	527	
May-01	511.07	390.40	489	
Jun-01	505.68	167.30	504	
Jul-01	412.26	139.60	404	
Aug-01	427.92	139.60	436	
Sep-01	409.71	309.00	412	
Oct-01	447.84	573.40	437	
Nov-01	539.82	818.00	539	
Dec-01	612.12	1094.60	572	
Jan-02	817.55	935.60	868	
Feb-02	635.92	824.60	639	
Mar-02	642.29	921.10	598	
Apr-02	651.11	653.30	599	
May-02	568.31	361.60	555	
Jun-02	462.46	175.60	458	
Jul-02	433.54	130.90	428	
Aug-02	445.58	182.80	440	
Sep-02	445.79	314.40	446	
Oct-02	473.63	444.30	505	
Nov-02	566.51	582.60	642	
Dec-02	552.02	845.20	592	

Yukon Electrical Company Limited
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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	744.25	989.10	778	
Feb-03	625.18	756.60	650	
Mar-03	609.25	834.50	593	
Apr-03	612.14	514.30	605	
May-03	559.97	363.70	546	
Jun-03	482.03	192.80	472	
Jul-03	472.76	84.40	482	
Aug-03	421.92	180.60	417	
Sep-03	459.71	359.20	445	
Oct-03	437.42	466.70	462	
Nov-03	584.07	874.60	565	
Dec-03	662.44	911.60	681	
Jan-04	795.06	1257.90	741	
Feb-04	716.36	697.20	761	
Mar-04	592.85	753.50	603	
Apr-04	589.84	466.60	598	
May-04	569.15	272.50	585	
Jun-04	439.01	83.70	464	
Jul-04	486.09	74.20	499	
Aug-04	395.12	101.70	416	
Sep-04	394.18	367.50	377	
Oct-04	488.31	540.50	488	
Nov-04	570.81	719.80	602	
Dec-04	637.87	899.50	661	
Jan-05	859.85	1165.80	836	
Feb-05	760.43	795.20	773	
Mar-05	642.22	613.70	698	
Apr-05	604.27	453.30	617	
May-05	506.22	256.60	527	
Jun-05	432.67	154.40	435	
Jul-05	450.86	132.60	445	
Aug-05	398.24	150.80	403	
Sep-05	469.63	299.30	475	
Oct-05	524.28	534.60	526	
Nov-05	557.58	762.60	575	
Dec-05	655.29	794.40	712	
Jan-06	841.77	1096.20	841	
Feb-06	737.13	821.30	741	
Mar-06	649.47	906.30	610	
Apr-06	691.39	519.10	683	
May-06	517.81	346.90	510	
Jun-06	590.90	173.10	587	
Jul-06	442.84	118.40	441	
Aug-06	462.30	201.60	451	
Sep-06	480.25	295.70	487	
Oct-06	496.77	520.50	503	
Nov-06	612.28	1162.20	500	
Dec-06	811.32	824.30	858	
Jan-07	830.63	912.00	889	
Feb-07	810.42	998.80	757	
Mar-07	791.75	954.20	737	
Apr-07	732.13	511.90	726	
May-07	554.95	322.10	555	
Jun-07	528.51	140.50	535	
Jul-07	458.69	102.30	462	
Aug-07	464.97	154.20	469	
Sep-07	451.01	308.40	453	
Oct-07	499.49	543.70	499	
Nov-07	229.05	724.60	259	
Dec-07	679.62	1069.50	647	

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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	824.10	1113.80	817	
Feb-08	961.03	954.60	922	
Mar-08	726.66	734.70	743	
Apr-08	687.44	517.30	680	
May-08	614.67	307.90	619	
Jun-08	493.04	225.60	472	
Jul-08	456.88	173.40	437	
Aug-08	506.62	187.70	500	
Sep-08	453.32	318.70	452	
Oct-08	496.10	563.00	489	
Nov-08	623.30	782.50	634	
Dec-08	724.74	1186.20	655	
Jan-09	909.35	1137.90	895	
Feb-09	893.36	955.40	854	
Mar-09	825.31	868.50	798	
Apr-09	763.93	515.20	757	
May-09	696.17	331.20	693	
Jun-09	516.90	144.10	522	
Jul-09	497.49	62.50	514	
Aug-09	440.61	158.30	443	
Sep-09	473.82	306.10	477	
Oct-09	560.75	541.80	561	
Nov-09	617.21	781.50	629	
Dec-09	746.27	943.40	755	
Jan-10	951.15	991.10	984	
Feb-10	924.83	679.20	975	
Mar-10	740.59	656.00	782	
Apr-10	675.83	461.20	686	
May-10	649.67	292.00	659	
Jun-10	530.25	171.90	527	
Jul-10	481.28	117.30	480	
Aug-10	459.19	146.20	466	
Sep-10	454.07	332.40	449	
Oct-10	576.27	520.40	583	
Nov-10	632.62	717.60	665	
Dec-10	691.97	1162.50	630	7885.06
Jan-11	1038.06	1010.20	1,065	
Feb-11	873.67	905.60	851	
Mar-11	930.27	901.70	893	
Apr-11	796.07	511.20	790	
May-11	587.24	296.20	596	
Jun-11	560.33	161.00	560	
Jul-11	456.89	127.80	452	
Aug-11	438.61	217.90	422	
Sep-11	516.96	328.50	513	
Nov-11	531.54	513.30	541	
Nov-11	615.93	936.25	577	
Dec-11	839.15	775.10	902	8160.56
Jan-12	851.88	1118.10	844	
Feb-12	1019.77	707.50	1,061	
Mar-12	711.70	756.20	721	
Apr-12	684.68	450.60	698	
May-12	622.42	350.80	613	
Jun-12	543.45	200.00	531	
Jul-12	484.51	140.10	476	
Aug-12	511.31	157.90	514	
Sep-12	519.75	287.15	529	
Oct-12	520.94	631.40	492	
Nov-12	704.44	969.60	655	
Dec-12	819.40	1196.80	746	7878.97
2013-F				7,974.9
2014-F				7,974.9
2015-F				7,974.9

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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	983.84	1165.70	961	
Feb-98	757.50	719.10	794	
Mar-98	736.82	756.60	746	
Apr-98	667.46	458.60	678	
May-98	640.89	270.60	657	
Jun-98	570.83	119.50	584	
Jul-98	589.06	111.60	590	
Aug-98	505.35	189.20	498	
Sep-98	599.34	327.80	595	
Oct-98	659.23	557.70	654	
Nov-98	688.74	792.30	696	
Dec-98	705.63	1051.80	680	
Jan-99	1022.46	1183.10	994	
Feb-99	836.84	976.40	792	
Mar-99	758.68	734.00	775	
Apr-99	734.47	508.80	730	
May-99	605.20	391.90	583	
Jun-99	616.08	153.90	618	
Jul-99	589.39	108.60	591	
Aug-99	538.63	145.70	545	
Sep-99	588.89	311.20	590	
Oct-99	650.77	499.80	664	
Nov-99	711.91	792.50	720	
Dec-99	771.21	844.00	811	
Jan-00	919.17	1082.90	922	
Feb-00	767.81	735.20	799	
Mar-00	696.01	659.20	736	
Apr-00	653.56	515.60	646	
May-00	647.12	382.00	628	
Jun-00	633.92	172.50	630	
Jul-00	589.23	142.10	580	
Aug-00	565.57	219.90	549	
Sep-00	624.94	354.20	613	
Oct-00	645.35	539.20	646	
Nov-00	694.52	691.20	734	
Dec-00	704.97	977.80	702	
Jan-01	947.85	722.70	1,064	
Feb-01	740.58	864.10	731	
Mar-01	687.40	765.30	694	
Apr-01	631.85	506.80	628	
May-01	667.55	390.40	646	
Jun-01	650.33	167.30	648	
Jul-01	567.84	139.60	559	
Aug-01	570.31	139.60	579	
Sep-01	569.35	309.00	571	
Oct-01	632.74	573.40	623	
Nov-01	719.41	818.00	719	
Dec-01	848.28	1094.60	809	
Jan-02	965.83	935.60	1,015	
Feb-02	752.27	824.60	755	
Mar-02	737.50	921.10	695	
Apr-02	771.65	653.30	721	
May-02	629.03	361.60	617	
Jun-02	599.90	175.60	595	
Jul-02	567.28	130.90	562	
Aug-02	566.34	182.80	561	
Sep-02	599.66	314.40	600	
Oct-02	638.58	444.30	669	
Nov-02	776.11	582.60	850	
Dec-02	624.76	845.20	664	

Yukon Electrical Company Limited
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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	924.87	989.10	957	
Feb-03	708.42	756.60	733	
Mar-03	661.09	834.50	646	
Apr-03	649.40	514.30	643	
May-03	595.58	363.70	582	
Jun-03	585.92	192.80	576	
Jul-03	545.20	84.40	554	
Aug-03	514.74	180.60	510	
Sep-03	564.92	359.20	551	
Oct-03	546.52	466.70	570	
Nov-03	668.22	874.60	650	
Dec-03	772.74	911.60	791	
Jan-04	872.87	1257.90	821	
Feb-04	767.27	697.20	810	
Mar-04	635.49	753.50	645	
Apr-04	672.11	466.60	680	
May-04	550.50	272.50	566	
Jun-04	506.18	83.70	530	
Jul-04	581.92	74.20	594	
Aug-04	489.54	101.70	510	
Sep-04	573.71	367.50	557	
Oct-04	567.32	540.50	568	
Nov-04	649.55	719.80	680	
Dec-04	765.21	899.50	787	
Jan-05	865.66	1165.80	843	
Feb-05	799.12	795.20	811	
Mar-05	619.53	613.70	673	
Apr-05	686.53	453.30	699	
May-05	568.24	256.60	589	
Jun-05	531.01	154.40	533	
Jul-05	561.76	132.60	556	
Aug-05	495.10	150.80	500	
Sep-05	646.17	299.30	651	
Oct-05	572.83	534.60	575	
Nov-05	687.06	762.60	704	
Dec-05	705.12	794.40	760	
Jan-06	876.57	1096.20	875	
Feb-06	787.19	821.30	791	
Mar-06	737.76	906.30	700	
Apr-06	634.57	519.10	626	
May-06	620.22	346.90	612	
Jun-06	565.22	173.10	561	
Jul-06	599.03	118.40	597	
Aug-06	530.52	201.60	519	
Sep-06	580.60	295.70	587	
Oct-06	513.53	520.50	520	
Nov-06	757.45	1162.20	649	
Dec-06	659.12	824.30	705	
Jan-07	1088.17	912.00	1,145	
Feb-07	791.83	998.80	740	
Mar-07	795.39	954.20	742	
Apr-07	713.40	511.90	707	
May-07	540.96	322.10	541	
Jun-07	629.17	140.50	636	
Jul-07	478.58	102.30	482	
Aug-07	493.46	154.20	497	
Sep-07	611.35	308.40	613	
Oct-07	554.34	543.70	554	
Nov-07	689.91	724.60	719	
Dec-07	745.97	1069.50	715	

Yukon Electrical Company Limited
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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	912.87	1113.80	906	
Feb-08	846.73	954.60	809	
Mar-08	843.51	734.70	859	
Apr-08	670.54	517.30	663	
May-08	563.76	307.90	568	
Jun-08	521.70	225.60	501	
Jul-08	603.53	173.40	585	
Aug-08	527.07	187.70	520	
Sep-08	586.83	318.70	586	
Oct-08	519.77	563.00	513	
Nov-08	668.89	782.50	680	
Dec-08	757.37	1186.20	689	
Jan-09	1021.75	1137.90	1,007	
Feb-09	730.55	955.40	693	
Mar-09	789.49	868.50	763	
Apr-09	640.24	515.20	633	
May-09	683.39	331.20	681	
Jun-09	548.03	144.10	553	
Jul-09	535.04	62.50	551	
Aug-09	507.97	158.30	510	
Sep-09	532.13	306.10	535	
Oct-09	577.93	541.80	578	
Nov-09	738.06	781.50	749	
Dec-09	700.84	943.40	709	
Jan-10	961.89	991.10	994	
Feb-10	714.53	679.20	763	
Mar-10	712.94	656.00	754	
Apr-10	609.79	461.20	620	
May-10	615.98	292.00	625	
Jun-10	578.19	171.90	575	
Jul-10	518.10	117.30	517	
Aug-10	488.66	146.20	495	
Sep-10	549.61	332.40	544	
Oct-10	572.26	520.40	579	
Nov-10	681.19	717.60	712	
Dec-10	710.29	1162.50	650	7827.21
Jan-11	999.60	1010.20	1,025	
Feb-11	753.69	905.60	731	
Mar-11	773.04	901.70	736	
Apr-11	659.04	511.20	653	
May-11	665.59	296.20	674	
Jun-11	541.03	161.00	541	
Jul-11	535.52	127.80	531	
Aug-11	466.57	217.90	450	
Sep-11	516.28	328.50	512	
Nov-11	600.63	513.30	609	
Nov-11	681.86	936.25	644	
Dec-11	735.64	775.10	797	7905.05
Jan-12	928.36	1118.10	920	
Feb-12	821.58	707.50	861	
Mar-12	730.15	756.20	739	
Apr-12	655.88	450.60	669	
May-12	548.21	350.80	539	
Jun-12	599.23	200.00	587	
Jul-12	537.57	140.10	529	
Aug-12	429.88	157.90	432	
Sep-12	560.48	287.15	569	
Oct-12	571.07	631.40	543	
Nov-12	670.46	969.60	623	
Dec-12	905.15	1196.80	834	7846.23
2013-F				7,859.5
2014-F				7,859.5
2015-F				7,859.5

Yukon Electrical Company Limited
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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	814.83	1165.70	793	
Feb-98	583.38	719.10	618	
Mar-98	544.14	756.60	553	
Apr-98	578.51	458.60	589	
May-98	446.48	270.60	462	
Jun-98	410.56	119.50	423	
Jul-98	499.27	111.60	500	
Aug-98	443.49	189.20	437	
Sep-98	458.11	327.80	454	
Oct-98	539.94	557.70	535	
Nov-98	553.91	792.30	561	
Dec-98	624.43	1051.80	600	
Jan-99	836.66	1183.10	810	
Feb-99	603.72	976.40	562	
Mar-99	658.99	734.00	674	
Apr-99	586.70	508.80	582	
May-99	457.76	391.90	437	
Jun-99	510.14	153.90	512	
Jul-99	508.78	108.60	510	
Aug-99	411.15	145.70	417	
Sep-99	463.34	311.20	465	
Oct-99	523.66	499.80	536	
Nov-99	511.67	792.50	519	
Dec-99	548.25	844.00	585	
Jan-00	836.92	1082.90	840	
Feb-00	564.40	735.20	594	
Mar-00	491.79	659.20	529	
Apr-00	545.27	515.60	539	
May-00	474.06	382.00	456	
Jun-00	513.85	172.50	510	
Jul-00	418.80	142.10	410	
Aug-00	422.89	219.90	407	
Sep-00	546.71	354.20	535	
Oct-00	487.08	539.20	488	
Nov-00	589.99	691.20	627	
Dec-00	565.52	977.80	563	
Jan-01	637.66	722.70	747	
Feb-01	570.31	864.10	562	
Mar-01	629.10	765.30	635	
Apr-01	537.20	506.80	533	
May-01	475.35	390.40	455	
Jun-01	515.46	167.30	514	
Jul-01	452.81	139.60	445	
Aug-01	423.69	139.60	431	
Sep-01	490.14	309.00	492	
Oct-01	473.38	573.40	464	
Nov-01	581.48	818.00	581	
Dec-01	640.26	1094.60	603	
Jan-02	639.45	935.60	686	
Feb-02	719.93	824.60	723	
Mar-02	537.74	921.10	498	
Apr-02	538.57	653.30	491	
May-02	583.89	361.60	572	
Jun-02	420.09	175.60	416	
Jul-02	427.53	130.90	422	
Aug-02	485.55	182.80	481	
Sep-02	415.97	314.40	416	
Oct-02	533.02	444.30	562	
Nov-02	528.75	582.60	598	
Dec-02	570.09	845.20	607	

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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	721.32	989.10	752	
Feb-03	546.55	756.60	570	
Mar-03	531.06	834.50	516	
Apr-03	434.00	514.30	428	
May-03	564.98	363.70	553	
Jun-03	427.05	192.80	418	
Jul-03	479.75	84.40	488	
Aug-03	427.74	180.60	423	
Sep-03	463.66	359.20	451	
Oct-03	515.88	466.70	538	
Nov-03	535.51	874.60	518	
Dec-03	622.70	911.60	640	
Jan-04	831.65	1257.90	783	
Feb-04	643.18	697.20	684	
Mar-04	439.96	753.50	449	
Apr-04	574.90	466.60	583	
May-04	432.44	272.50	447	
Jun-04	450.06	83.70	473	
Jul-04	510.64	74.20	522	
Aug-04	405.29	101.70	424	
Sep-04	531.29	367.50	516	
Oct-04	503.38	540.50	504	
Nov-04	529.19	719.80	558	
Dec-04	575.73	899.50	597	
Jan-05	925.27	1165.80	904	
Feb-05	614.63	795.20	626	
Mar-05	534.56	613.70	585	
Apr-05	545.34	453.30	557	
May-05	480.04	256.60	499	
Jun-05	416.22	154.40	418	
Jul-05	466.39	132.60	461	
Aug-05	430.48	150.80	435	
Sep-05	522.47	299.30	527	
Oct-05	458.91	534.60	461	
Nov-05	552.59	762.60	569	
Dec-05	576.80	794.40	629	
Jan-06	815.85	1096.20	815	
Feb-06	599.60	821.30	603	
Mar-06	738.67	906.30	703	
Apr-06	511.35	519.10	504	
May-06	501.90	346.90	495	
Jun-06	523.50	173.10	520	
Jul-06	441.61	118.40	440	
Aug-06	419.21	201.60	409	
Sep-06	540.22	295.70	546	
Oct-06	477.26	520.50	483	
Nov-06	546.24	1162.20	444	
Dec-06	681.70	824.30	725	
Jan-07	821.97	912.00	875	
Feb-07	590.96	998.80	542	
Mar-07	736.70	954.20	687	
Apr-07	529.70	511.90	524	
May-07	616.82	322.10	617	
Jun-07	521.68	140.50	528	
Jul-07	443.72	102.30	447	
Aug-07	465.45	154.20	469	
Sep-07	500.47	308.40	502	
Oct-07	549.57	543.70	549	
Nov-07	645.22	724.60	673	
Dec-07	589.02	1069.50	560	

Yukon Electrical Company Limited
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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	883.32	1113.80	877	
Feb-08	943.04	954.60	908	
Mar-08	541.12	734.70	556	
Apr-08	545.58	517.30	538	
May-08	563.22	307.90	567	
Jun-08	417.21	225.60	398	
Jul-08	424.77	173.40	407	
Aug-08	530.76	187.70	524	
Sep-08	477.15	318.70	476	
Oct-08	601.14	563.00	595	
Nov-08	565.56	782.50	576	
Dec-08	641.23	1186.20	577	
Jan-09	1032.69	1137.90	1,019	
Feb-09	915.59	955.40	880	
Mar-09	504.65	868.50	480	
Apr-09	543.06	515.20	537	
May-09	603.03	331.20	600	
Jun-09	418.40	144.10	423	
Jul-09	512.97	62.50	528	
Aug-09	427.44	158.30	430	
Sep-09	440.10	306.10	443	
Oct-09	561.57	541.80	561	
Nov-09	569.68	781.50	580	
Dec-09	659.17	943.40	667	
Jan-10	891.22	991.10	921	
Feb-10	641.06	679.20	687	
Mar-10	608.19	656.00	646	
Apr-10	650.73	461.20	660	
May-10	491.31	292.00	500	
Jun-10	460.20	171.90	457	
Jul-10	531.56	117.30	530	
Aug-10	387.03	146.20	393	
Sep-10	526.23	332.40	521	
Oct-10	544.32	520.40	550	
Nov-10	617.76	717.60	647	
Dec-10	785.33	1162.50	728	7242.12
Jan-11	858.50	1010.20	883	
Feb-11	654.02	905.60	633	
Mar-11	823.05	901.70	789	
Apr-11	554.51	511.20	549	
May-11	616.54	296.20	624	
Jun-11	456.23	161.00	456	
Jul-11	510.58	127.80	506	
Aug-11	434.33	217.90	419	
Sep-11	532.19	328.50	528	
Nov-11	532.41	513.30	541	
Nov-11	599.18	936.25	564	
Dec-11	711.46	775.10	769	7260.93
Jan-12	956.09	1118.10	949	
Feb-12	675.67	707.50	713	
Mar-12	733.04	756.20	742	
Apr-12	577.68	450.60	590	
May-12	510.64	350.80	502	
Jun-12	501.48	200.00	490	
Jul-12	424.34	140.10	416	
Aug-12	390.29	157.90	393	
Sep-12	504.10	287.15	512	
Oct-12	496.11	631.40	469	
Nov-12	744.48	969.60	699	
Dec-12	776.29	1196.80	709	7184.92
2013-F				7,229.3
2014-F				7,229.3
2015-F				7,229.3

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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1058.61	1165.70	1,027	
Feb-98	802.93	719.10	852	
Mar-98	782.98	756.60	795	
Apr-98	635.51	458.60	650	
May-98	527.58	270.60	549	
Jun-98	502.43	119.50	520	
Jul-98	553.31	111.60	554	
Aug-98	450.98	189.20	441	
Sep-98	560.04	327.80	555	
Oct-98	567.35	557.70	560	
Nov-98	592.30	792.30	603	
Dec-98	841.44	1051.80	807	
Jan-99	955.97	1183.10	917	
Feb-99	798.82	976.40	738	
Mar-99	706.66	734.00	728	
Apr-99	703.14	508.80	696	
May-99	575.71	391.90	546	
Jun-99	504.68	153.90	508	
Jul-99	581.67	108.60	584	
Aug-99	471.87	145.70	480	
Sep-99	470.53	311.20	472	
Oct-99	640.23	499.80	658	
Nov-99	646.77	792.50	657	
Dec-99	723.70	844.00	777	
Jan-00	962.75	1082.90	967	
Feb-00	777.86	735.20	820	
Mar-00	678.69	659.20	732	
Apr-00	787.68	515.60	778	
May-00	514.79	382.00	489	
Jun-00	649.68	172.50	645	
Jul-00	466.75	142.10	454	
Aug-00	475.15	219.90	452	
Sep-00	628.05	354.20	611	
Oct-00	600.16	539.20	601	
Nov-00	615.52	691.20	669	
Dec-00	854.24	977.80	851	
Jan-01	823.92	722.70	982	
Feb-01	680.11	864.10	667	
Mar-01	846.67	765.30	855	
Apr-01	594.39	506.80	589	
May-01	579.91	390.40	551	
Jun-01	560.11	167.30	557	
Jul-01	467.58	139.60	456	
Aug-01	431.08	139.60	442	
Sep-01	510.75	309.00	513	
Oct-01	560.69	573.40	547	
Nov-01	734.63	818.00	734	
Dec-01	730.50	1094.60	677	
Jan-02	822.54	935.60	889	
Feb-02	853.68	824.60	858	
Mar-02	656.59	921.10	599	
Apr-02	665.33	653.30	597	
May-02	614.79	361.60	598	
Jun-02	447.73	175.60	441	
Jul-02	427.71	130.90	420	
Aug-02	511.99	182.80	505	
Sep-02	414.68	314.40	415	
Oct-02	493.82	444.30	535	
Nov-02	662.60	582.60	762	
Dec-02	621.65	845.20	675	

Yukon Electrical Company Limited
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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	845.05	989.10	889	
Feb-03	717.88	756.60	751	
Mar-03	629.68	834.50	609	
Apr-03	549.62	514.30	541	
May-03	560.55	363.70	543	
Jun-03	430.80	192.80	417	
Jul-03	456.65	84.40	469	
Aug-03	386.93	180.60	381	
Sep-03	402.75	359.20	384	
Oct-03	473.35	466.70	505	
Nov-03	675.36	874.60	651	
Dec-03	727.12	911.60	752	
Jan-04	883.78	1257.90	813	
Feb-04	769.43	697.20	828	
Mar-04	640.26	753.50	654	
Apr-04	685.20	466.60	696	
May-04	498.86	272.50	520	
Jun-04	453.36	83.70	486	
Jul-04	486.84	74.20	503	
Aug-04	414.96	101.70	442	
Sep-04	538.59	367.50	516	
Oct-04	500.05	540.50	500	
Nov-04	567.59	719.80	609	
Dec-04	714.77	899.50	745	
Jan-05	999.04	1165.80	968	
Feb-05	829.08	795.20	846	
Mar-05	632.61	613.70	706	
Apr-05	687.74	453.30	705	
May-05	513.18	256.60	541	
Jun-05	435.44	154.40	438	
Jul-05	489.22	132.60	481	
Aug-05	456.94	150.80	463	
Sep-05	583.92	299.30	591	
Oct-05	496.19	534.60	499	
Nov-05	593.04	762.60	616	
Dec-05	736.25	794.40	811	
Jan-06	960.57	1096.20	959	
Feb-06	800.58	821.30	806	
Mar-06	697.45	906.30	646	
Apr-06	729.55	519.10	718	
May-06	556.74	346.90	546	
Jun-06	532.97	173.10	528	
Jul-06	425.93	118.40	424	
Aug-06	393.88	201.60	379	
Sep-06	522.31	295.70	531	
Oct-06	524.67	520.50	533	
Nov-06	688.63	1162.20	541	
Dec-06	891.59	824.30	954	
Jan-07	778.56	912.00	855	
Feb-07	714.26	998.80	644	
Mar-07	962.61	954.20	891	
Apr-07	682.24	511.90	674	
May-07	505.16	322.10	505	
Jun-07	527.06	140.50	536	
Jul-07	421.53	102.30	426	
Aug-07	468.88	154.20	474	
Sep-07	445.35	308.40	448	
Oct-07	562.99	543.70	562	
Nov-07	732.80	724.60	772	
Dec-07	702.63	1069.50	660	

Yukon Electrical Company Limited
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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	844.07	1113.80	835	
Feb-08	1085.47	954.60	1,034	
Mar-08	692.21	734.70	714	
Apr-08	608.14	517.30	598	
May-08	652.16	307.90	658	
Jun-08	494.57	225.60	467	
Jul-08	506.30	173.40	481	
Aug-08	527.41	187.70	518	
Sep-08	571.02	318.70	570	
Oct-08	557.13	563.00	548	
Nov-08	809.42	782.50	824	
Dec-08	766.96	1186.20	675	
Jan-09	1265.61	1137.90	1,246	
Feb-09	802.19	955.40	751	
Mar-09	805.56	868.50	770	
Apr-09	683.92	515.20	674	
May-09	677.89	331.20	674	
Jun-09	569.55	144.10	577	
Jul-09	595.67	62.50	617	
Aug-09	538.97	158.30	542	
Sep-09	432.36	306.10	436	
Oct-09	701.93	541.80	702	
Nov-09	620.17	781.50	635	
Dec-09	850.55	943.40	862	
Jan-10	1055.40	991.10	1,099	
Feb-10	770.51	679.20	837	
Mar-10	660.56	656.00	716	
Apr-10	749.98	461.20	764	
May-10	552.02	292.00	565	
Jun-10	526.57	171.90	522	
Jul-10	564.03	117.30	562	
Aug-10	480.88	146.20	489	
Sep-10	604.33	332.40	597	
Oct-10	586.26	520.40	595	
Nov-10	657.45	717.60	700	
Dec-10	957.38	1162.50	875	8319.79
Jan-11	1094.65	1010.20	1,130	
Feb-11	955.36	905.60	925	
Mar-11	955.04	901.70	905	
Apr-11	885.86	511.20	878	
May-11	651.54	296.20	663	
Jun-11	541.38	161.00	541	
Jul-11	561.73	127.80	555	
Aug-11	498.85	217.90	477	
Sep-11	623.09	328.50	617	
Nov-11	596.88	513.30	609	
Nov-11	642.83	936.25	592	
Dec-11	965.29	775.10	1,048	8940.71
Jan-12	1092.16	1118.10	1,081	
Feb-12	980.46	707.50	1,035	
Mar-12	973.30	756.20	986	
Apr-12	710.75	450.60	729	
May-12	586.09	350.80	574	
Jun-12	641.20	200.00	624	
Jul-12	503.49	140.10	492	
Aug-12	525.95	157.90	529	
Sep-12	506.90	287.15	519	
Oct-12	559.65	631.40	521	
Nov-12	904.69	969.60	840	
Dec-12	984.57	1196.80	888	8817.46
2013-F				8,692.7
2014-F				8,692.7
2015-F				8,692.7

Yukon Electrical Company Limited
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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1086.53	1165.70	1,054	
Feb-98	894.52	719.10	946	
Mar-98	698.46	756.60	711	
Apr-98	734.53	458.60	750	
May-98	712.52	270.60	736	
Jun-98	521.79	119.50	540	
Jul-98	523.55	111.60	524	
Aug-98	585.02	189.20	575	
Sep-98	613.51	327.80	608	
Oct-98	783.35	557.70	776	
Nov-98	715.70	792.30	727	
Dec-98	891.62	1051.80	855	
Jan-99	1202.83	1183.10	1,162	
Feb-99	867.89	976.40	804	
Mar-99	785.96	734.00	809	
Apr-99	874.25	508.80	867	
May-99	651.94	391.90	621	
Jun-99	572.35	153.90	575	
Jul-99	644.52	108.60	647	
Aug-99	563.70	145.70	573	
Sep-99	670.87	311.20	673	
Oct-99	854.54	499.80	873	
Nov-99	779.73	792.50	791	
Dec-99	833.26	844.00	890	
Jan-00	1247.38	1082.90	1,252	
Feb-00	838.80	735.20	883	
Mar-00	812.30	659.20	869	
Apr-00	899.88	515.60	890	
May-00	691.76	382.00	665	
Jun-00	714.63	172.50	709	
Jul-00	584.60	142.10	572	
Aug-00	613.12	219.90	589	
Sep-00	787.57	354.20	770	
Oct-00	748.53	539.20	749	
Nov-00	942.50	691.20	999	
Dec-00	703.96	977.80	700	
Jan-01	999.24	722.70	1,165	
Feb-01	825.88	864.10	813	
Mar-01	905.03	765.30	914	
Apr-01	691.19	506.80	685	
May-01	684.13	390.40	653	
Jun-01	647.41	167.30	644	
Jul-01	575.81	139.60	564	
Aug-01	501.88	139.60	514	
Sep-01	713.12	309.00	716	
Oct-01	673.23	573.40	659	
Nov-01	926.77	818.00	926	
Dec-01	859.92	1094.60	804	
Jan-02	1107.62	935.60	1,178	
Feb-02	1065.08	824.60	1,070	
Mar-02	774.38	921.10	713	
Apr-02	748.68	653.30	677	
May-02	768.50	361.60	751	
Jun-02	532.39	175.60	526	
Jul-02	550.67	130.90	543	
Aug-02	688.70	182.80	681	
Sep-02	661.12	314.40	661	
Oct-02	692.18	444.30	736	
Nov-02	698.09	582.60	803	
Dec-02	867.76	845.20	924	

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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	871.39	989.10	918	
Feb-03	804.10	756.60	839	
Mar-03	769.27	834.50	747	
Apr-03	727.56	514.30	718	
May-03	770.30	363.70	752	
Jun-03	580.73	192.80	566	
Jul-03	643.85	84.40	657	
Aug-03	595.08	180.60	588	
Sep-03	655.14	359.20	635	
Oct-03	783.86	466.70	817	
Nov-03	782.44	874.60	757	
Dec-03	1061.74	911.60	1,088	
Jan-04	1003.81	1257.90	929	
Feb-04	822.85	697.20	885	
Mar-04	780.66	753.50	795	
Apr-04	883.00	466.60	895	
May-04	642.85	272.50	665	
Jun-04	674.85	83.70	710	
Jul-04	592.92	74.20	610	
Aug-04	558.72	101.70	588	
Sep-04	653.99	367.50	631	
Oct-04	809.17	540.50	809	
Nov-04	861.12	719.80	905	
Dec-04	724.34	899.50	756	
Jan-05	1183.78	1165.80	1,151	
Feb-05	909.36	795.20	927	
Mar-05	731.02	613.70	808	
Apr-05	848.22	453.30	866	
May-05	638.99	256.60	668	
Jun-05	703.20	154.40	706	
Jul-05	533.44	132.60	525	
Aug-05	593.29	150.80	600	
Sep-05	749.13	299.30	756	
Oct-05	657.93	534.60	661	
Nov-05	769.26	762.60	794	
Dec-05	817.06	794.40	896	
Jan-06	1146.78	1096.20	1,145	
Feb-06	759.28	821.30	765	
Mar-06	966.29	906.30	912	
Apr-06	678.30	519.10	667	
May-06	665.18	346.90	654	
Jun-06	667.39	173.10	662	
Jul-06	558.64	118.40	556	
Aug-06	509.76	201.60	494	
Sep-06	730.68	295.70	739	
Oct-06	681.16	520.50	690	
Nov-06	848.43	1162.20	693	
Dec-06	915.06	824.30	980	
Jan-07	1168.96	912.00	1,250	
Feb-07	871.57	998.80	798	
Mar-07	1033.18	954.20	957	
Apr-07	692.54	511.90	684	
May-07	721.82	322.10	722	
Jun-07	656.80	140.50	666	
Jul-07	450.58	102.30	455	
Aug-07	729.07	154.20	734	
Sep-07	579.48	308.40	583	
Oct-07	684.48	543.70	683	
Nov-07	929.33	724.60	971	
Dec-07	732.54	1069.50	688	

Yukon Electrical Company Limited
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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1142.47	1113.80	1,133	
Feb-08	1286.97	954.60	1,233	
Mar-08	958.31	734.70	981	
Apr-08	575.54	517.30	565	
May-08	810.33	307.90	817	
Jun-08	608.33	225.60	579	
Jul-08	440.43	173.40	413	
Aug-08	623.13	187.70	613	
Sep-08	567.82	318.70	566	
Oct-08	735.62	563.00	726	
Nov-08	807.28	782.50	823	
Dec-08	884.48	1186.20	787	
Jan-09	1349.67	1137.90	1,329	
Feb-09	1030.29	955.40	976	
Mar-09	1005.63	868.50	968	
Apr-09	692.25	515.20	682	
May-09	715.75	331.20	712	
Jun-09	547.04	144.10	555	
Jul-09	605.96	62.50	629	
Aug-09	534.67	158.30	538	
Sep-09	619.24	306.10	623	
Oct-09	840.58	541.80	840	
Nov-09	863.76	781.50	880	
Dec-09	924.28	943.40	936	
Jan-10	972.81	991.10	1,018	
Feb-10	825.37	679.20	895	
Mar-10	777.19	656.00	835	
Apr-10	824.62	461.20	839	
May-10	680.58	292.00	694	
Jun-10	551.48	171.90	546	
Jul-10	751.59	117.30	750	
Aug-10	519.94	146.20	529	
Sep-10	692.34	332.40	685	
Oct-10	693.91	520.40	703	
Nov-10	773.77	717.60	818	
Dec-10	836.17	1162.50	750	9062.61
Jan-11	1250.81	1010.20	1,288	
Feb-11	924.10	905.60	892	
Mar-11	905.22	901.70	853	
Apr-11	759.94	511.20	752	
May-11	764.85	296.20	776	
Jun-11	544.81	161.00	545	
Jul-11	642.51	127.80	636	
Aug-11	593.52	217.90	570	
Sep-11	714.31	328.50	708	
Nov-11	677.94	513.30	690	
Nov-11	890.35	936.25	837	
Dec-11	942.47	775.10	1,030	9577.29
Jan-12	1316.41	1118.10	1,305	
Feb-12	897.93	707.50	955	
Mar-12	1081.45	756.20	1,094	
Apr-12	597.87	450.60	617	
May-12	702.24	350.80	689	
Jun-12	799.19	200.00	782	
Jul-12	444.11	140.10	432	
Aug-12	650.10	157.90	654	
Sep-12	633.41	287.15	646	
Oct-12	724.40	631.40	684	
Nov-12	1161.91	969.60	1,093	
Dec-12	1135.86	1196.80	1,034	9984.89
2013-F				9,541.6
2014-F				9,541.6
2015-F				9,541.6

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Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	874.55	1165.70	855	
Feb-98	636.30	719.10	668	
Mar-98	680.81	756.60	689	
Apr-98	495.37	458.60	505	
May-98	543.47	270.60	557	
Jun-98	480.21	119.50	491	
Jul-98	210.67	111.60	211	
Aug-98	585.17	189.20	579	
Sep-98	489.61	327.80	486	
Oct-98	562.92	557.70	558	
Nov-98	515.39	792.30	522	
Dec-98	631.39	1051.80	609	
Jan-99	758.98	1183.10	734	
Feb-99	605.30	976.40	567	
Mar-99	597.31	734.00	611	
Apr-99	685.87	508.80	682	
May-99	459.29	391.90	440	
Jun-99	441.67	153.90	444	
Jul-99	535.10	108.60	536	
Aug-99	448.78	145.70	454	
Sep-99	439.71	311.20	441	
Oct-99	647.73	499.80	659	
Nov-99	581.70	792.50	588	
Dec-99	648.90	844.00	683	
Jan-00	903.37	1082.90	906	
Feb-00	652.46	735.20	679	
Mar-00	772.30	659.20	807	
Apr-00	471.82	515.60	466	
May-00	572.87	382.00	557	
Jun-00	603.80	172.50	601	
Jul-00	426.62	142.10	419	
Aug-00	432.41	219.90	418	
Sep-00	466.62	354.20	456	
Oct-00	611.91	539.20	612	
Nov-00	504.54	691.20	539	
Dec-00	672.91	977.80	671	
Jan-01	719.83	722.70	821	
Feb-01	591.68	864.10	584	
Mar-01	657.71	765.30	663	
Apr-01	607.24	506.80	604	
May-01	573.66	390.40	555	
Jun-01	456.47	167.30	455	
Jul-01	434.01	139.60	427	
Aug-01	398.59	139.60	406	
Sep-01	494.61	309.00	496	
Oct-01	429.23	573.40	420	
Nov-01	551.22	818.00	551	
Dec-01	542.01	1094.60	508	
Jan-02	653.86	935.60	697	
Feb-02	715.86	824.60	719	
Mar-02	540.61	921.10	504	
Apr-02	525.12	653.30	482	
May-02	536.55	361.60	526	
Jun-02	393.60	175.60	390	
Jul-02	434.95	130.90	430	
Aug-02	508.20	182.80	504	
Sep-02	417.07	314.40	417	
Oct-02	461.60	444.30	488	
Nov-02	635.48	582.60	699	
Dec-02	557.29	845.20	591	

Yukon Electrical Company Limited
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Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	783.92	989.10	812	
Feb-03	655.33	756.60	677	
Mar-03	621.21	834.50	608	
Apr-03	590.57	514.30	585	
May-03	558.87	363.70	548	
Jun-03	457.13	192.80	448	
Jul-03	504.68	84.40	512	
Aug-03	408.95	180.60	405	
Sep-03	463.75	359.20	452	
Oct-03	432.28	466.70	453	
Nov-03	528.04	874.60	512	
Dec-03	638.87	911.60	655	
Jan-04	792.39	1257.90	747	
Feb-04	655.38	697.20	693	
Mar-04	667.89	753.50	677	
Apr-04	590.63	466.60	598	
May-04	555.43	272.50	569	
Jun-04	477.73	83.70	499	
Jul-04	485.17	74.20	496	
Aug-04	444.82	101.70	462	
Sep-04	390.05	367.50	376	
Oct-04	546.44	540.50	547	
Nov-04	588.90	719.80	615	
Dec-04	624.32	899.50	643	
Jan-05	900.64	1165.80	881	
Feb-05	686.79	795.20	697	
Mar-05	690.73	613.70	737	
Apr-05	737.85	453.30	749	
May-05	537.04	256.60	555	
Jun-05	454.68	154.40	456	
Jul-05	499.65	132.60	494	
Aug-05	481.44	150.80	486	
Sep-05	468.61	299.30	473	
Oct-05	581.06	534.60	583	
Nov-05	555.41	762.60	570	
Dec-05	647.48	794.40	695	
Jan-06	856.21	1096.20	855	
Feb-06	730.66	821.30	734	
Mar-06	645.01	906.30	612	
Apr-06	720.45	519.10	713	
May-06	589.11	346.90	582	
Jun-06	512.44	173.10	509	
Jul-06	437.86	118.40	436	
Aug-06	422.35	201.60	413	
Sep-06	562.12	295.70	567	
Oct-06	463.28	520.50	469	
Nov-06	468.83	1162.20	375	
Dec-06	743.18	824.30	783	
Jan-07	755.01	912.00	804	
Feb-07	663.57	998.80	619	
Mar-07	762.87	954.20	717	
Apr-07	651.80	511.90	647	
May-07	509.32	322.10	509	
Jun-07	546.58	140.50	552	
Jul-07	441.92	102.30	445	
Aug-07	392.80	154.20	396	
Sep-07	529.69	308.40	532	
Oct-07	464.20	543.70	463	
Nov-07	646.91	724.60	672	
Dec-07	626.85	1069.50	600	

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Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	695.27	1113.80	689	
Feb-08	795.35	954.60	763	
Mar-08	587.17	734.70	601	
Apr-08	571.63	517.30	565	
May-08	549.53	307.90	553	
Jun-08	559.91	225.60	542	
Jul-08	399.54	173.40	383	
Aug-08	533.24	187.70	527	
Sep-08	447.71	318.70	447	
Oct-08	409.45	563.00	403	
Nov-08	634.01	782.50	643	
Dec-08	560.56	1186.20	502	
Jan-09	860.77	1137.90	848	
Feb-09	643.45	955.40	611	
Mar-09	645.28	868.50	623	
Apr-09	648.59	515.20	643	
May-09	594.31	331.20	592	
Jun-09	494.44	144.10	499	
Jul-09	520.22	62.50	534	
Aug-09	407.68	158.30	410	
Sep-09	425.84	306.10	428	
Oct-09	592.41	541.80	592	
Nov-09	637.09	781.50	647	
Dec-09	586.46	943.40	594	
Jan-10	815.74	991.10	843	
Feb-10	685.26	679.20	728	
Mar-10	633.69	656.00	669	
Apr-10	750.63	461.20	759	
May-10	485.36	292.00	494	
Jun-10	441.99	171.90	439	
Jul-10	506.08	117.30	505	
Aug-10	413.70	146.20	419	
Sep-10	472.21	332.40	468	
Oct-10	596.04	520.40	602	
Nov-10	567.52	717.60	595	
Dec-10	637.92	1162.50	585	7104.80
Jan-11	1043.99	1010.20	1,066	
Feb-11	764.53	905.60	745	
Mar-11	684.51	901.70	653	
Apr-11	877.27	511.20	872	
May-11	686.25	296.20	693	
Jun-11	459.01	161.00	459	
Jul-11	548.97	127.80	545	
Aug-11	454.18	217.90	440	
Sep-11	523.52	328.50	520	
Nov-11	507.80	513.30	515	
Nov-11	573.69	936.25	541	
Dec-11	811.99	775.10	865	7915.38
Jan-12	787.32	1118.10	780	
Feb-12	730.70	707.50	765	
Mar-12	835.48	756.20	843	
Apr-12	661.65	450.60	673	
May-12	566.76	350.80	559	
Jun-12	588.77	200.00	578	
Jul-12	435.38	140.10	428	
Aug-12	586.84	157.90	589	
Sep-12	343.63	287.15	351	
Oct-12	499.01	631.40	474	
Nov-12	645.99	969.60	604	
Dec-12	785.18	1196.80	723	7369.77
2013-F				7,463.3
2014-F				7,463.3
2015-F				7,463.3

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Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	659.49	1165.70	643	
Feb-98	485.53	719.10	511	
Mar-98	519.32	756.60	526	
Apr-98	426.18	458.60	434	
May-98	407.38	270.60	419	
Jun-98	391.14	119.50	400	
Jul-98	390.86	111.60	391	
Aug-98	376.39	189.20	371	
Sep-98	419.40	327.80	417	
Oct-98	434.86	557.70	431	
Nov-98	467.71	792.30	473	
Dec-98	381.25	1051.80	363	
Jan-99	556.79	1183.10	537	
Feb-99	538.03	976.40	507	
Mar-99	528.31	734.00	540	
Apr-99	454.14	508.80	451	
May-99	371.97	391.90	357	
Jun-99	392.64	153.90	394	
Jul-99	444.38	108.60	445	
Aug-99	361.36	145.70	366	
Sep-99	427.53	311.20	428	
Oct-99	443.01	499.80	452	
Nov-99	486.75	792.50	492	
Dec-99	457.62	844.00	485	
Jan-00	659.64	1082.90	662	
Feb-00	429.70	735.20	452	
Mar-00	459.54	659.20	487	
Apr-00	425.46	515.60	421	
May-00	459.06	382.00	446	
Jun-00	439.88	172.50	437	
Jul-00	460.75	142.10	454	
Aug-00	421.70	219.90	410	
Sep-00	417.62	354.20	409	
Oct-00	463.85	539.20	464	
Nov-00	495.43	691.20	523	
Dec-00	597.34	977.80	596	
Jan-01	459.64	722.70	541	
Feb-01	424.66	864.10	418	
Mar-01	478.15	765.30	483	
Apr-01	416.66	506.80	414	
May-01	479.80	390.40	465	
Jun-01	499.99	167.30	499	
Jul-01	430.57	139.60	425	
Aug-01	407.80	139.60	414	
Sep-01	465.47	309.00	467	
Oct-01	467.67	573.40	461	
Nov-01	492.48	818.00	492	
Dec-01	585.11	1094.60	558	
Jan-02	652.56	935.60	687	
Feb-02	543.74	824.60	546	
Mar-02	535.00	921.10	505	
Apr-02	602.74	653.30	567	
May-02	465.03	361.60	456	
Jun-02	415.04	175.60	412	
Jul-02	475.03	130.90	471	
Aug-02	427.53	182.80	424	
Sep-02	473.96	314.40	474	
Oct-02	499.51	444.30	521	
Nov-02	569.87	582.60	621	
Dec-02	501.99	845.20	529	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	650.35	989.10	673	
Feb-03	459.59	756.60	477	
Mar-03	509.70	834.50	499	
Apr-03	427.03	514.30	422	
May-03	417.94	363.70	409	
Jun-03	457.03	192.80	450	
Jul-03	419.88	84.40	426	
Aug-03	405.08	180.60	402	
Sep-03	497.59	359.20	488	
Oct-03	431.58	466.70	448	
Nov-03	551.07	874.60	538	
Dec-03	641.68	911.60	655	
Jan-04	553.93	1257.90	517	
Feb-04	588.61	697.20	619	
Mar-04	545.28	753.50	552	
Apr-04	524.71	466.60	531	
May-04	424.15	272.50	435	
Jun-04	419.00	83.70	436	
Jul-04	388.09	74.20	397	
Aug-04	435.21	101.70	449	
Sep-04	402.16	367.50	391	
Oct-04	383.32	540.50	383	
Nov-04	489.42	719.80	511	
Dec-04	460.83	899.50	476	
Jan-05	674.26	1165.80	658	
Feb-05	513.32	795.20	522	
Mar-05	456.36	613.70	494	
Apr-05	466.43	453.30	475	
May-05	438.62	256.60	453	
Jun-05	416.84	154.40	418	
Jul-05	341.25	132.60	337	
Aug-05	420.90	150.80	424	
Sep-05	415.08	299.30	419	
Oct-05	420.50	534.60	422	
Nov-05	488.13	762.60	500	
Dec-05	513.11	794.40	552	
Jan-06	690.78	1096.20	690	
Feb-06	583.41	821.30	586	
Mar-06	586.70	906.30	560	
Apr-06	511.24	519.10	506	
May-06	521.14	346.90	516	
Jun-06	402.97	173.10	400	
Jul-06	408.76	118.40	408	
Aug-06	449.72	201.60	442	
Sep-06	444.88	295.70	449	
Oct-06	451.06	520.50	456	
Nov-06	590.73	1162.20	515	
Dec-06	646.43	824.30	678	
Jan-07	836.41	912.00	876	
Feb-07	608.51	998.80	572	
Mar-07	654.62	954.20	617	
Apr-07	618.36	511.90	614	
May-07	584.69	322.10	585	
Jun-07	468.06	140.50	473	
Jul-07	512.12	102.30	514	
Aug-07	265.04	154.20	268	
Sep-07	427.81	308.40	429	
Oct-07	465.07	543.70	464	
Nov-07	559.47	724.60	580	
Dec-07	556.70	1069.50	535	

Yukon Electrical Company Limited
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Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	727.49	1113.80	723	
Feb-08	561.57	954.60	535	
Mar-08	613.78	734.70	625	
Apr-08	582.56	517.30	577	
May-08	523.88	307.90	527	
Jun-08	516.18	225.60	502	
Jul-08	411.51	173.40	398	
Aug-08	437.22	187.70	432	
Sep-08	417.29	318.70	417	
Oct-08	387.33	563.00	383	
Nov-08	557.02	782.50	565	
Dec-08	551.78	1186.20	504	
Jan-09	747.87	1137.90	738	
Feb-09	630.79	955.40	604	
Mar-09	592.23	868.50	574	
Apr-09	615.90	515.20	611	
May-09	470.80	331.20	469	
Jun-09	430.29	144.10	434	
Jul-09	446.52	62.50	458	
Aug-09	374.36	158.30	376	
Sep-09	452.88	306.10	455	
Oct-09	443.99	541.80	444	
Nov-09	562.05	781.50	570	
Dec-09	566.49	943.40	572	
Jan-10	832.12	991.10	854	
Feb-10	600.72	679.20	635	
Mar-10	516.74	656.00	545	
Apr-10	616.28	461.20	623	
May-10	516.82	292.00	523	
Jun-10	422.30	171.90	420	
Jul-10	439.59	117.30	439	
Aug-10	302.70	146.20	307	
Sep-10	450.83	332.40	447	
Oct-10	493.99	520.40	499	
Nov-10	589.14	717.60	611	
Dec-10	591.44	1162.50	549	6452.46
Jan-11	748.39	1010.20	767	
Feb-11	732.11	905.60	716	
Mar-11	655.86	901.70	630	
Apr-11	625.01	511.20	621	
May-11	486.39	296.20	492	
Jun-11	448.66	161.00	449	
Jul-11	403.85	127.80	401	
Aug-11	399.74	217.90	388	
Sep-11	475.29	328.50	472	
Nov-11	506.92	513.30	513	
Nov-11	523.42	936.25	497	
Dec-11	729.11	775.10	772	6718.31
Jan-12	831.41	1118.10	826	
Feb-12	684.62	707.50	713	
Mar-12	693.23	756.20	700	
Apr-12	505.55	450.60	515	
May-12	454.85	350.80	449	
Jun-12	550.67	200.00	542	
Jul-12	435.97	140.10	430	
Aug-12	459.09	157.90	461	
Sep-12	445.74	287.15	452	
Oct-12	486.15	631.40	466	
Nov-12	574.91	969.60	541	
Dec-12	799.31	1196.80	749	6843.09
2013-F				6,671.3
2014-F				6,671.3
2015-F				6,671.3

Yukon Electrical Company Limited
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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1144.75	1165.70	1,115	
Feb-98	879.34	719.10	926	
Mar-98	511.17	756.60	523	
Apr-98	673.26	458.60	687	
May-98	539.35	270.60	560	
Jun-98	498.14	119.50	515	
Jul-98	569.92	111.60	571	
Aug-98	552.94	189.20	543	
Sep-98	489.27	327.80	484	
Oct-98	680.98	557.70	674	
Nov-98	795.49	792.30	806	
Dec-98	789.62	1051.80	756	
Jan-99	927.15	1183.10	890	
Feb-99	743.00	976.40	685	
Mar-99	735.92	734.00	757	
Apr-99	667.80	508.80	661	
May-99	531.03	391.90	503	
Jun-99	552.43	153.90	555	
Jul-99	546.28	108.60	548	
Aug-99	438.29	145.70	447	
Sep-99	584.66	311.20	586	
Oct-99	603.78	499.80	621	
Nov-99	711.25	792.50	721	
Dec-99	919.70	844.00	971	
Jan-00	816.58	1082.90	820	
Feb-00	788.80	735.20	829	
Mar-00	676.58	659.20	728	
Apr-00	596.98	515.60	588	
May-00	618.73	382.00	594	
Jun-00	523.47	172.50	519	
Jul-00	554.25	142.10	542	
Aug-00	503.78	219.90	482	
Sep-00	598.14	354.20	582	
Oct-00	638.83	539.20	640	
Nov-00	671.18	691.20	722	
Dec-00	734.21	977.80	731	
Jan-01	856.02	722.70	1,007	
Feb-01	692.23	864.10	680	
Mar-01	636.65	765.30	645	
Apr-01	617.46	506.80	612	
May-01	593.56	390.40	566	
Jun-01	551.68	167.30	549	
Jul-01	511.08	139.60	500	
Aug-01	597.97	139.60	609	
Sep-01	651.75	309.00	654	
Oct-01	682.88	573.40	670	
Nov-01	743.42	818.00	743	
Dec-01	763.23	1094.60	712	
Jan-02	921.80	935.60	986	
Feb-02	792.95	824.60	797	
Mar-02	744.35	921.10	689	
Apr-02	839.64	653.30	774	
May-02	576.61	361.60	560	
Jun-02	514.92	175.60	509	
Jul-02	528.76	130.90	521	
Aug-02	521.16	182.80	514	
Sep-02	536.78	314.40	537	
Oct-02	655.21	444.30	695	
Nov-02	667.65	582.60	763	
Dec-02	652.76	845.20	704	

Yukon Electrical Company Limited
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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1051.67	989.10	1,094	
Feb-03	753.97	756.60	786	
Mar-03	668.50	834.50	648	
Apr-03	711.85	514.30	703	
May-03	594.25	363.70	577	
Jun-03	537.02	192.80	524	
Jul-03	552.81	84.40	564	
Aug-03	559.42	180.60	553	
Sep-03	590.49	359.20	573	
Oct-03	579.49	466.70	610	
Nov-03	852.01	874.60	829	
Dec-03	838.29	911.60	862	
Jan-04	1057.46	1257.90	990	
Feb-04	855.01	697.20	911	
Mar-04	803.16	753.50	816	
Apr-04	868.10	466.60	879	
May-04	572.62	272.50	593	
Jun-04	535.48	83.70	567	
Jul-04	601.46	74.20	617	
Aug-04	517.93	101.70	544	
Sep-04	622.13	367.50	601	
Oct-04	610.32	540.50	611	
Nov-04	715.21	719.80	755	
Dec-04	1006.16	899.50	1,035	
Jan-05	1000.46	1165.80	971	
Feb-05	928.86	795.20	945	
Mar-05	741.70	613.70	812	
Apr-05	691.10	453.30	707	
May-05	571.96	256.60	599	
Jun-05	603.88	154.40	606	
Jul-05	527.80	132.60	520	
Aug-05	525.03	150.80	531	
Sep-05	591.35	299.30	598	
Oct-05	636.62	534.60	639	
Nov-05	714.13	762.60	736	
Dec-05	800.30	794.40	872	
Jan-06	1004.65	1096.20	1,003	
Feb-06	976.21	821.30	982	
Mar-06	988.24	906.30	939	
Apr-06	708.01	519.10	697	
May-06	585.97	346.90	576	
Jun-06	602.91	173.10	598	
Jul-06	487.78	118.40	486	
Aug-06	532.01	201.60	517	
Sep-06	631.19	295.70	639	
Oct-06	615.55	520.50	624	
Nov-06	692.12	1162.20	552	
Dec-06	925.52	824.30	985	
Jan-07	1060.67	912.00	1,134	
Feb-07	841.01	998.80	774	
Mar-07	1041.74	954.20	973	
Apr-07	827.13	511.90	819	
May-07	614.63	322.10	615	
Jun-07	687.44	140.50	696	
Jul-07	563.43	102.30	568	
Aug-07	582.03	154.20	587	
Sep-07	540.50	308.40	543	
Oct-07	682.49	543.70	681	
Nov-07	754.70	724.60	792	
Dec-07	791.70	1069.50	751	

Yukon Electrical Company Limited
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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	946.60	1113.80	938	
Feb-08	996.79	954.60	948	
Mar-08	717.75	734.70	738	
Apr-08	730.91	517.30	721	
May-08	635.69	307.90	641	
Jun-08	607.28	225.60	581	
Jul-08	563.62	173.40	539	
Aug-08	644.32	187.70	635	
Sep-08	532.27	318.70	531	
Oct-08	617.15	563.00	608	
Nov-08	772.11	782.50	786	
Dec-08	1011.94	1186.20	924	
Jan-09	945.57	1137.90	927	
Feb-09	924.94	955.40	876	
Mar-09	833.86	868.50	800	
Apr-09	741.12	515.20	732	
May-09	584.15	331.20	580	
Jun-09	499.03	144.10	506	
Jul-09	609.51	62.50	630	
Aug-09	588.94	158.30	592	
Sep-09	590.61	306.10	594	
Oct-09	691.68	541.80	691	
Nov-09	787.30	781.50	802	
Dec-09	846.34	943.40	857	
Jan-10	1096.43	991.10	1,138	
Feb-10	876.39	679.20	940	
Mar-10	815.75	656.00	868	
Apr-10	743.03	461.20	756	
May-10	694.12	292.00	706	
Jun-10	564.29	171.90	560	
Jul-10	611.61	117.30	610	
Aug-10	629.85	146.20	638	
Sep-10	568.33	332.40	561	
Oct-10	662.11	520.40	671	
Nov-10	677.58	717.60	718	
Dec-10	786.73	1162.50	708	8873.71
Jan-11	1133.18	1010.20	1,167	
Feb-11	866.96	905.60	838	
Mar-11	865.69	901.70	818	
Apr-11	724.28	511.20	717	
May-11	611.99	296.20	622	
Jun-11	533.41	161.00	533	
Jul-11	603.68	127.80	598	
Aug-11	606.01	217.90	585	
Sep-11	594.50	328.50	589	
Nov-11	674.03	513.30	685	
Nov-11	886.06	936.25	837	
Dec-11	1049.39	775.10	1,129	9118.80
Jan-12	1099.68	1118.10	1,089	
Feb-12	902.13	707.50	954	
Mar-12	862.06	756.20	874	
Apr-12	668.21	450.60	686	
May-12	644.93	350.80	633	
Jun-12	658.48	200.00	643	
Jul-12	560.48	140.10	549	
Aug-12	608.08	157.90	611	
Sep-12	595.85	287.15	607	
Oct-12	716.23	631.40	679	
Nov-12	872.74	969.60	811	
Dec-12	1057.34	1196.80	965	9101.26
2013-F				9,031.3
2014-F				9,031.3
2015-F				9,031.3

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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	568.72	1165.70	551	
Feb-98	390.62	719.10	418	
Mar-98	359.52	756.60	366	
Apr-98	335.08	458.60	343	
May-98	295.19	270.60	307	
Jun-98	269.54	119.50	279	
Jul-98	307.02	111.60	307	
Aug-98	284.27	189.20	279	
Sep-98	300.45	327.80	297	
Oct-98	340.74	557.70	337	
Nov-98	348.62	792.30	354	
Dec-98	377.59	1051.80	358	
Jan-99	537.10	1183.10	516	
Feb-99	423.80	976.40	390	
Mar-99	374.64	734.00	387	
Apr-99	372.71	508.80	369	
May-99	292.18	391.90	276	
Jun-99	271.03	153.90	273	
Jul-99	306.15	108.60	307	
Aug-99	280.95	145.70	286	
Sep-99	295.00	311.20	296	
Oct-99	287.72	499.80	298	
Nov-99	312.59	792.50	318	
Dec-99	373.56	844.00	403	
Jan-00	453.57	1082.90	456	
Feb-00	337.29	735.20	361	
Mar-00	324.96	659.20	355	
Apr-00	308.29	515.60	303	
May-00	298.64	382.00	284	
Jun-00	262.97	172.50	260	
Jul-00	275.80	142.10	269	
Aug-00	299.81	219.90	287	
Sep-00	274.55	354.20	265	
Oct-00	269.64	539.20	270	
Nov-00	291.25	691.20	321	
Dec-00	367.92	977.80	366	
Jan-01	343.68	722.70	431	
Feb-01	359.34	864.10	352	
Mar-01	303.10	765.30	308	
Apr-01	284.31	506.80	281	
May-01	273.10	390.40	257	
Jun-01	241.49	167.30	240	
Jul-01	256.79	139.60	250	
Aug-01	278.56	139.60	285	
Sep-01	261.86	309.00	263	
Oct-01	274.62	573.40	267	
Nov-01	324.16	818.00	324	
Dec-01	439.49	1094.60	410	
Jan-02	419.66	935.60	457	
Feb-02	352.27	824.60	355	
Mar-02	321.00	921.10	289	
Apr-02	314.88	653.30	277	
May-02	283.33	361.60	274	
Jun-02	248.35	175.60	245	
Jul-02	272.12	130.90	268	
Aug-02	290.73	182.80	287	
Sep-02	253.23	314.40	253	
Oct-02	299.37	444.30	322	
Nov-02	317.13	582.60	373	
Dec-02	368.73	845.20	398	

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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	438.03	989.10	463	
Feb-03	352.66	756.60	371	
Mar-03	336.25	834.50	325	
Apr-03	313.80	514.30	309	
May-03	281.55	363.70	272	
Jun-03	255.82	192.80	248	
Jul-03	287.82	84.40	295	
Aug-03	270.46	180.60	267	
Sep-03	277.39	359.20	267	
Oct-03	243.60	466.70	261	
Nov-03	263.42	874.60	250	
Dec-03	376.97	911.60	391	
Jan-04	426.31	1257.90	387	
Feb-04	377.81	697.20	410	
Mar-04	340.32	753.50	348	
Apr-04	360.04	466.60	366	
May-04	281.20	272.50	293	
Jun-04	250.25	83.70	269	
Jul-04	291.10	74.20	300	
Aug-04	256.88	101.70	272	
Sep-04	317.18	367.50	305	
Oct-04	304.78	540.50	305	
Nov-04	336.15	719.80	359	
Dec-04	375.44	899.50	392	
Jan-05	532.50	1165.80	515	
Feb-05	428.12	795.20	437	
Mar-05	324.57	613.70	365	
Apr-05	316.33	453.30	326	
May-05	271.63	256.60	287	
Jun-05	252.45	154.40	254	
Jul-05	286.19	132.60	282	
Aug-05	300.47	150.80	304	
Sep-05	276.06	299.30	280	
Oct-05	312.45	534.60	314	
Nov-05	346.21	762.60	359	
Dec-05	412.04	794.40	454	
Jan-06	549.87	1096.20	549	
Feb-06	435.94	821.30	439	
Mar-06	453.87	906.30	425	
Apr-06	380.81	519.10	375	
May-06	327.13	346.90	321	
Jun-06	262.47	173.10	260	
Jul-06	320.19	118.40	319	
Aug-06	276.52	201.60	268	
Sep-06	308.15	295.70	313	
Oct-06	325.52	520.50	330	
Nov-06	424.64	1162.20	343	
Dec-06	526.02	824.30	561	
Jan-07	596.08	912.00	639	
Feb-07	549.43	998.80	510	
Mar-07	455.28	954.20	415	
Apr-07	357.51	511.90	353	
May-07	332.11	322.10	332	
Jun-07	297.45	140.50	302	
Jul-07	285.50	102.30	288	
Aug-07	297.61	154.20	300	
Sep-07	297.38	308.40	299	
Oct-07	340.93	543.70	340	
Nov-07	470.95	724.60	493	
Dec-07	509.59	1069.50	486	

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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	529.39	1113.80	524	
Feb-08	605.05	954.60	577	
Mar-08	413.02	734.70	425	
Apr-08	340.57	517.30	335	
May-08	289.64	307.90	293	
Jun-08	281.46	225.60	266	
Jul-08	269.32	173.40	255	
Aug-08	319.52	187.70	314	
Sep-08	293.14	318.70	292	
Oct-08	317.14	563.00	312	
Nov-08	489.59	782.50	498	
Dec-08	511.70	1186.20	460	
Jan-09	688.78	1137.90	678	
Feb-09	556.80	955.40	528	
Mar-09	490.70	868.50	471	
Apr-09	425.92	515.20	421	
May-09	291.63	331.20	289	
Jun-09	270.57	144.10	275	
Jul-09	322.52	62.50	335	
Aug-09	280.87	158.30	283	
Sep-09	303.99	306.10	306	
Oct-09	385.39	541.80	385	
Nov-09	451.41	781.50	460	
Dec-09	512.91	943.40	519	
Jan-10	631.26	991.10	655	
Feb-10	511.78	679.20	549	
Mar-10	425.32	656.00	456	
Apr-10	423.81	461.20	431	
May-10	351.03	292.00	358	
Jun-10	281.45	171.90	279	
Jul-10	316.55	117.30	316	
Aug-10	311.28	146.20	316	
Sep-10	336.06	332.40	332	
Oct-10	414.58	520.40	419	
Nov-10	417.00	717.60	441	
Dec-10	536.77	1162.50	491	5042.87
Jan-11	730.78	1010.20	750	
Feb-11	521.04	905.60	504	
Mar-11	548.00	901.70	520	
Apr-11	392.61	511.20	388	
May-11	364.87	296.20	371	
Jun-11	286.41	161.00	286	
Jul-11	324.11	127.80	321	
Aug-11	317.59	217.90	305	
Sep-11	343.45	328.50	340	
Nov-11	361.83	513.30	368	
Nov-11	517.46	936.25	489	
Dec-11	494.27	775.10	540	5184.71
Jan-12	700.79	1118.10	695	
Feb-12	507.40	707.50	538	
Mar-12	504.90	756.20	512	
Apr-12	345.99	450.60	356	
May-12	352.07	350.80	345	
Jun-12	348.46	200.00	339	
Jul-12	314.99	140.10	309	
Aug-12	344.42	157.90	346	
Sep-12	333.82	287.15	340	
Oct-12	414.21	631.40	393	
Nov-12	513.07	969.60	477	
Dec-12	637.55	1196.80	584	5233.20
2013-F				5,153.6
2014-F				5,153.6
2015-F				5,153.6

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	922.61	1165.70	888	
Feb-98	719.54	719.10	774	
Mar-98	633.42	756.60	647	
Apr-98	589.41	458.60	606	
May-98	493.54	270.60	518	
Jun-98	439.08	119.50	459	
Jul-98	487.36	111.60	488	
Aug-98	466.85	189.20	456	
Sep-98	554.45	327.80	548	
Oct-98	560.71	557.70	553	
Nov-98	655.54	792.30	667	
Dec-98	886.52	1051.80	848	
Jan-99	906.99	1183.10	864	
Feb-99	812.23	976.40	745	
Mar-99	660.72	734.00	685	
Apr-99	615.38	508.80	608	
May-99	514.03	391.90	481	
Jun-99	473.06	153.90	476	
Jul-99	461.31	108.60	463	
Aug-99	428.75	145.70	438	
Sep-99	511.22	311.20	513	
Oct-99	517.48	499.80	537	
Nov-99	589.23	792.50	601	
Dec-99	824.03	844.00	884	
Jan-00	828.68	1082.90	833	
Feb-00	665.54	735.20	713	
Mar-00	578.48	659.20	638	
Apr-00	569.25	515.60	559	
May-00	525.15	382.00	497	
Jun-00	429.62	172.50	424	
Jul-00	451.81	142.10	438	
Aug-00	493.73	219.90	468	
Sep-00	501.65	354.20	483	
Oct-00	580.63	539.20	582	
Nov-00	591.03	691.20	651	
Dec-00	788.26	977.80	784	
Jan-01	714.57	722.70	890	
Feb-01	674.39	864.10	660	
Mar-01	609.15	765.30	619	
Apr-01	560.93	506.80	554	
May-01	554.49	390.40	522	
Jun-01	444.60	167.30	442	
Jul-01	480.68	139.60	468	
Aug-01	438.08	139.60	451	
Sep-01	452.60	309.00	456	
Oct-01	571.87	573.40	557	
Nov-01	642.53	818.00	642	
Dec-01	910.51	1094.60	851	
Jan-02	805.85	935.60	880	
Feb-02	644.89	824.60	650	
Mar-02	627.55	921.10	563	
Apr-02	658.99	653.30	583	
May-02	505.70	361.60	487	
Jun-02	445.33	175.60	438	
Jul-02	445.86	130.90	437	
Aug-02	465.07	182.80	457	
Sep-02	463.34	314.40	464	
Oct-02	559.59	444.30	606	
Nov-02	576.02	582.60	687	
Dec-02	744.72	845.20	804	

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	772.78	989.10	822	
Feb-03	611.36	756.60	648	
Mar-03	600.85	834.50	577	
Apr-03	602.07	514.30	592	
May-03	459.68	363.70	440	
Jun-03	450.12	192.80	435	
Jul-03	466.38	84.40	480	
Aug-03	455.98	180.60	449	
Sep-03	521.70	359.20	501	
Oct-03	492.29	466.70	528	
Nov-03	697.32	874.60	670	
Dec-03	822.87	911.60	851	
Jan-04	807.21	1257.90	729	
Feb-04	657.43	697.20	723	
Mar-04	618.36	753.50	633	
Apr-04	623.60	466.60	636	
May-04	482.32	272.50	506	
Jun-04	494.34	83.70	531	
Jul-04	457.03	74.20	475	
Aug-04	460.76	101.70	491	
Sep-04	524.11	367.50	499	
Oct-04	543.78	540.50	544	
Nov-04	634.98	719.80	681	
Dec-04	834.53	899.50	868	
Jan-05	869.05	1165.80	834	
Feb-05	755.37	795.20	774	
Mar-05	604.75	613.70	686	
Apr-05	524.07	453.30	543	
May-05	521.30	256.60	552	
Jun-05	451.77	154.40	455	
Jul-05	473.22	132.60	464	
Aug-05	476.85	150.80	484	
Sep-05	513.36	299.30	521	
Oct-05	533.60	534.60	537	
Nov-05	699.34	762.60	725	
Dec-05	774.39	794.40	858	
Jan-06	848.61	1096.20	847	
Feb-06	796.05	821.30	802	
Mar-06	757.64	906.30	700	
Apr-06	581.66	519.10	569	
May-06	548.72	346.90	537	
Jun-06	461.75	173.10	456	
Jul-06	466.02	118.40	463	
Aug-06	508.04	201.60	491	
Sep-06	526.65	295.70	536	
Oct-06	582.31	520.50	592	
Nov-06	880.03	1162.20	716	
Dec-06	885.09	824.30	954	
Jan-07	895.16	912.00	981	
Feb-07	874.50	998.80	796	
Mar-07	718.47	954.20	638	
Apr-07	588.70	511.90	580	
May-07	496.13	322.10	496	
Jun-07	474.10	140.50	484	
Jul-07	480.39	102.30	485	
Aug-07	512.91	154.20	518	
Sep-07	497.29	308.40	501	
Oct-07	644.31	543.70	643	
Nov-07	795.58	724.60	839	
Dec-07	899.95	1069.50	853	

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	975.11	1113.80	965	
Feb-08	955.69	954.60	899	
Mar-08	727.86	734.70	752	
Apr-08	658.41	517.30	647	
May-08	525.74	307.90	532	
Jun-08	487.43	225.60	457	
Jul-08	470.87	173.40	442	
Aug-08	556.13	187.70	546	
Sep-08	518.14	318.70	517	
Oct-08	593.70	563.00	583	
Nov-08	844.54	782.50	861	
Dec-08	1073.85	1186.20	971	
Jan-09	1064.61	1137.90	1,043	
Feb-09	918.50	955.40	861	
Mar-09	851.77	868.50	812	
Apr-09	765.56	515.20	755	
May-09	500.95	331.20	497	
Jun-09	493.95	144.10	502	
Jul-09	502.61	62.50	527	
Aug-09	471.85	158.30	475	
Sep-09	559.26	306.10	564	
Oct-09	611.99	541.80	612	
Nov-09	771.66	781.50	789	
Dec-09	1004.31	943.40	1,017	
Jan-10	987.15	991.10	1,035	
Feb-10	811.06	679.20	885	
Mar-10	737.86	656.00	799	
Apr-10	707.72	461.20	723	
May-10	561.34	292.00	576	
Jun-10	472.98	171.90	468	
Jul-10	525.23	117.30	523	
Aug-10	498.35	146.20	508	
Sep-10	621.63	332.40	613	
Oct-10	671.29	520.40	681	
Nov-10	761.67	717.60	809	
Dec-10	991.46	1162.50	900	8519.99
Jan-11	1273.29	1010.20	1,312	
Feb-11	915.97	905.60	882	
Mar-11	936.96	901.70	882	
Apr-11	777.29	511.20	769	
May-11	606.37	296.20	619	
Jun-11	516.93	161.00	517	
Jul-11	490.14	127.80	483	
Aug-11	558.09	217.90	533	
Sep-11	583.69	328.50	577	
Nov-11	658.14	513.30	671	
Nov-11	874.10	936.25	817	
Dec-11	1081.26	775.10	1,174	9236.76
Jan-12	1122.06	1118.10	1,110	
Feb-12	981.19	707.50	1,042	
Mar-12	814.35	756.20	828	
Apr-12	631.96	450.60	652	
May-12	635.15	350.80	621	
Jun-12	526.83	200.00	508	
Jul-12	509.33	140.10	496	
Aug-12	583.43	157.90	587	
Sep-12	558.34	287.15	572	
Oct-12	702.15	631.40	659	
Nov-12	949.97	969.60	877	
Dec-12	1294.29	1196.80	1,186	9139.81
2013-F				8,965.5
2014-F				8,965.5
2015-F				8,965.5

Yukon Electrical Company Limited
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Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	906.21	1165.70	879.57	
Feb-98	638.94	719.10	680.91	
Mar-98	763.85	756.60	774.25	
Apr-98	559.58	458.60	572.12	
May-98	412.38	270.60	431.08	
Jun-98	347.61	119.50	362.63	
Jul-98	401.03	111.60	401.55	
Aug-98	457.29	189.20	448.80	
Sep-98	401.65	327.80	397.08	
Oct-98	605.18	557.70	599.14	
Nov-98	676.97	792.30	685.95	
Dec-98	731.56	1051.80	701.75	
Jan-99	943.04	1183.10	910	
Feb-99	797.96	976.40	746	
Mar-99	523.43	734.00	542	
Apr-99	442.96	508.80	437	
May-99	379.52	391.90	354	
Jun-99	308.64	153.90	311	
Jul-99	321.09	108.60	323	
Aug-99	273.18	145.70	281	
Sep-99	370.68	311.20	372	
Oct-99	352.64	499.80	368	
Nov-99	450.04	792.50	459	
Dec-99	477.70	844.00	523	
Jan-00	805.58	1082.90	809	
Feb-00	503.88	735.20	540	
Mar-00	419.58	659.20	465	
Apr-00	463.79	515.60	456	
May-00	329.30	382.00	307	
Jun-00	274.71	172.50	270	
Jul-00	324.96	142.10	314	
Aug-00	293.78	219.90	274	
Sep-00	353.82	354.20	340	
Oct-00	380.95	539.20	382	
Nov-00	428.87	691.20	475	
Dec-00	701.70	977.80	699	
Jan-01	393.70	722.70	528	
Feb-01	532.00	864.10	521	
Mar-01	446.39	765.30	454	
Apr-01	443.87	506.80	439	
May-01	309.96	390.40	285	
Jun-01	297.65	167.30	295	
Jul-01	251.04	139.60	241	
Aug-01	206.42	139.60	216	
Sep-01	326.21	309.00	328	
Oct-01	288.08	573.40	276	
Nov-01	428.08	818.00	428	
Dec-01	610.00	1094.60	565	
Jan-02	648.79	935.60	706	
Feb-02	478.50	824.60	482	
Mar-02	420.75	921.10	371	
Apr-02	336.54	653.30	278	
May-02	292.92	361.60	279	
Jun-02	217.63	175.60	212	
Jul-02	243.21	130.90	237	
Aug-02	280.83	182.80	275	
Sep-02	238.42	314.40	239	
Oct-02	308.20	444.30	343	
Nov-02	409.88	582.60	495	
Dec-02	475.24	845.20	521	

Yukon Electrical Company Limited
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Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	480.32	989.10	518	
Feb-03	620.92	756.60	649	
Mar-03	448.00	834.50	430	
Apr-03	370.56	514.30	363	
May-03	342.68	363.70	328	
Jun-03	287.88	192.80	276	
Jul-03	351.29	84.40	362	
Aug-03	321.54	180.60	316	
Sep-03	502.45	359.20	486	
Oct-03	342.54	466.70	370	
Nov-03	534.22	874.60	513	
Dec-03	849.17	911.60	870	
Jan-04	987.42	1257.90	927	
Feb-04	833.67	697.20	884	
Mar-04	625.29	753.50	637	
Apr-04	544.58	466.60	554	
May-04	387.75	272.50	406	
Jun-04	338.42	83.70	366	
Jul-04	342.38	74.20	357	
Aug-04	333.40	101.70	357	
Sep-04	391.08	367.50	372	
Oct-04	462.92	540.50	463	
Nov-04	607.00	719.80	642	
Dec-04	430.42	899.50	456	
Jan-05	799.25	1165.80	773	
Feb-05	616.25	795.20	631	
Mar-05	488.39	613.70	551	
Apr-05	432.06	453.30	447	
May-05	302.50	256.60	326	
Jun-05	415.44	154.40	418	
Jul-05	332.69	132.60	326	
Aug-05	403.48	150.80	409	
Sep-05	350.66	299.30	356	
Oct-05	368.41	534.60	371	
Nov-05	377.39	762.60	397	
Dec-05	382.15	794.40	446	
Jan-06	486.15	1096.20	485	
Feb-06	684.48	821.30	689	
Mar-06	472.24	906.30	428	
Apr-06	422.03	519.10	413	
May-06	422.56	346.90	414	
Jun-06	420.13	173.10	416	
Jul-06	362.21	118.40	360	
Aug-06	315.26	201.60	302	
Sep-06	380.33	295.70	387	
Oct-06	339.06	520.50	347	
Nov-06	460.60	1162.20	335	
Dec-06	658.26	824.30	711	
Jan-07	812.80	912.00	878	
Feb-07	624.60	998.80	565	
Mar-07	600.89	954.20	539	
Apr-07	602.97	511.90	596	
May-07	320.69	322.10	321	
Jun-07	347.81	140.50	355	
Jul-07	350.89	102.30	355	
Aug-07	318.14	154.20	322	
Sep-07	372.57	308.40	375	
Oct-07	326.69	543.70	326	
Nov-07	511.03	724.60	545	
Dec-07	390.59	1069.50	354	

Yukon Electrical Company Limited
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Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	669.92	1113.80	662	
Feb-08	644.32	954.60	601	
Mar-08	464.41	734.70	483	
Apr-08	431.89	517.30	423	
May-08	395.39	307.90	401	
Jun-08	298.92	225.60	275	
Jul-08	310.56	173.40	289	
Aug-08	355.80	187.70	348	
Sep-08	302.62	318.70	301	
Oct-08	282.58	563.00	275	
Nov-08	521.36	782.50	534	
Dec-08	517.43	1186.20	439	
Jan-09	803.71	1137.90	787	
Feb-09	443.17	955.40	399	
Mar-09	477.46	868.50	447	
Apr-09	271.33	515.20	263	
May-09	224.88	331.20	222	
Jun-09	275.81	144.10	282	
Jul-09	292.86	62.50	311	
Aug-09	277.24	158.30	280	
Sep-09	343.81	306.10	347	
Oct-09	352.12	541.80	352	
Nov-09	337.55	781.50	350	
Dec-09	340.86	943.40	350	
Jan-10	598.31	991.10	635	
Feb-10	387.39	679.20	444	
Mar-10	373.39	656.00	420	
Apr-10	436.93	461.20	449	
May-10	324.41	292.00	335	
Jun-10	280.33	171.90	276	
Jul-10	314.88	117.30	313	
Aug-10	287.07	146.20	294	
Sep-10	361.88	332.40	356	
Oct-10	383.38	520.40	391	
Nov-10	407.80	717.60	444	
Dec-10	482.51	1162.50	412	4770.11
Jan-11	703.02	1010.20	733	
Feb-11	581.05	905.60	555	
Mar-11	733.63	901.70	691	
Apr-11	517.78	511.20	511	
May-11	392.76	296.20	402	
Jun-11	326.12	161.00	326	
Jul-11	280.35	127.80	275	
Aug-11	284.50	217.90	266	
Sep-11	376.95	328.50	372	
Nov-11	445.03	513.30	455	
Nov-11	503.27	936.25	460	
Dec-11	658.38	775.10	729	5775.67
Jan-12	744.80	1118.10	735	
Feb-12	761.55	707.50	808	
Mar-12	642.83	756.20	653	
Apr-12	541.75	450.60	557	
May-12	352.56	350.80	342	
Jun-12	300.41	200.00	286	
Jul-12	305.73	140.10	296	
Aug-12	373.76	157.90	377	
Sep-12	332.63	287.15	343	
Oct-12	372.08	631.40	339	
Nov-12	511.66	969.60	456	
Dec-12	687.90	1196.80	605	5798.13
2013-F				5,448.0
2014-F				5,448.0
2015-F				5,448.0

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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1059.13	1409.70	1,002	
Feb-98	791.03	942.00	785	
Mar-98	739.96	843.40	735	
Apr-98	661.48	500.10	664	
May-98	553.52	211.00	584	
Jun-98	504.32	89.00	519	
Jul-98	460.33	65.70	468	
Aug-98	480.62	156.80	476	
Sep-98	569.91	320.70	559	
Oct-98	599.93	561.20	588	
Nov-98	790.29	958.10	761	
Dec-98	788.21	1252.70	726	
Jan-99	934.05	1350.20	898	
Feb-99	773.36	1066.40	724	
Mar-99	711.18	871.40	696	
Apr-99	678.26	506.40	678	
May-99	598.20	372.20	572	
Jun-99	539.70	140.20	536	
Jul-99	478.75	99.40	475	
Aug-99	498.93	127.80	505	
Sep-99	579.53	292.50	579	
Oct-99	577.38	519.80	580	
Nov-99	709.78	939.90	687	
Dec-99	698.42	1013.00	720	
Jan-00	921.12	1344.80	887	
Feb-00	843.97	956.00	833	
Mar-00	688.04	750.10	715	
Apr-00	664.42	590.90	635	
May-00	638.13	373.80	611	
Jun-00	526.49	158.00	517	
Jul-00	542.56	84.30	544	
Aug-00	520.26	216.90	495	
Sep-00	545.37	314.80	537	
Oct-00	616.71	575.80	600	
Nov-00	680.74	858.40	687	
Dec-00	756.54	1222.80	705	
Jan-01	974.72	1043.40	1,046	
Feb-01	692.01	1031.00	655	
Mar-01	683.09	844.90	677	
Apr-01	657.56	535.80	647	
May-01	578.49	366.60	554	
Jun-01	535.74	155.50	527	
Jul-01	505.80	120.30	494	
Aug-01	495.96	120.60	504	
Sep-01	537.17	299.60	534	
Oct-01	597.60	577.00	580	
Nov-01	670.73	975.00	636	
Dec-01	731.64	1275.40	662	
Jan-02	904.19	1246.30	905	
Feb-02	724.91	970.30	709	
Mar-02	724.43	991.60	667	
Apr-02	759.43	694.80	693	
May-02	592.82	365.90	569	
Jun-02	540.27	147.80	534	
Jul-02	468.10	121.60	456	
Aug-02	542.99	181.50	530	
Sep-02	531.50	331.00	517	
Oct-02	576.38	514.80	581	
Nov-02	670.27	821.90	689	
Dec-02	686.08	1117.90	671	

Yukon Electrical Company Limited
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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	883.76	1177.50	908	
Feb-03	664.22	964.70	650	
Mar-03	665.22	899.50	640	
Apr-03	729.91	554.40	713	
May-03	647.82	341.60	632	
Jun-03	475.11	179.90	457	
Jul-03	488.70	56.60	499	
Aug-03	496.69	163.00	490	
Sep-03	533.65	330.20	520	
Oct-03	535.94	526.10	537	
Nov-03	683.69	963.90	652	
Dec-03	725.42	1095.50	718	
Jan-04	846.90	1365.60	805	
Feb-04	805.97	881.20	821	
Mar-04	709.32	809.90	716	
Apr-04	671.18	497.40	674	
May-04	507.37	292.30	509	
Jun-04	561.64	74.10	581	
Jul-04	514.33	35.60	532	
Aug-04	479.73	145.70	479	
Sep-04	510.47	370.70	482	
Oct-04	567.03	565.00	554	
Nov-04	782.65	875.50	782	
Dec-04	801.75	1070.70	803	
Jan-05	1013.04	1330.30	984	
Feb-05	610.26	941.80	604	
Mar-05	632.58	726.90	668	
Apr-05	618.87	464.80	633	
May-05	581.25	256.90	596	
Jun-05	444.66	126.60	446	
Jul-05	493.56	136.90	476	
Aug-05	448.88	162.20	442	
Sep-05	509.23	297.30	507	
Oct-05	621.21	541.70	616	
Nov-05	647.76	758.40	689	
Dec-05	742.88	1061.00	748	
Jan-06	943.00	1185.20	965	
Feb-06	910.37	1016.70	878	
Mar-06	826.74	960.50	780	
Apr-06	714.95	528.20	707	
May-06	583.71	371.10	558	
Jun-06	616.54	136.50	614	
Jul-06	548.45	79.20	551	
Aug-06	556.71	171.70	547	
Sep-06	563.11	292.40	562	
Oct-06	675.43	543.30	670	
Nov-06	837.25	1196.20	725	
Dec-06	906.05	1050.00	915	
Jan-07	1105.27	1102.40	1,156	
Feb-07	908.98	1017.30	876	
Mar-07	920.03	1001.90	859	
Apr-07	949.68	543.00	937	
May-07	681.49	332.20	669	
Jun-07	544.25	122.60	547	
Jul-07	588.79	88.60	588	
Aug-07	533.70	143.10	534	
Sep-07	571.41	314.70	563	
Oct-07	691.25	553.10	683	
Nov-07	797.41	956.60	769	
Dec-07	858.46	1255.10	796	

Yukon Electrical Company Limited
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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1143.55	1300.10	1,125	
Feb-08	992.38	1064.20	943	
Mar-08	792.01	833.30	790	
Apr-08	927.25	554.00	911	
May-08	649.38	295.60	650	
Jun-08	584.03	191.00	562	
Jul-08	564.68	131.50	549	
Aug-08	618.23	154.00	615	
Sep-08	578.57	304.20	574	
Oct-08	747.97	523.50	750	
Nov-08	826.82	879.00	825	
Dec-08	851.76	1386.50	743	
Jan-09	1345.06	1329.30	1,316	
Feb-09	1012.90	1089.50	955	
Mar-09	960.47	1054.20	881	
Apr-09	835.74	590.00	806	
May-09	641.94	356.00	622	
Jun-09	535.32	130.60	535	
Jul-09	630.86	89.00	630	
Aug-09	559.61	134.40	563	
Sep-09	676.16	279.40	680	
Oct-09	690.80	606.90	663	
Nov-09	787.50	996.50	745	
Dec-09	955.06	1273.66	886	
Jan-10	1239.27	1141.42	1,276	
Feb-10	900.03	965.80	886	
Mar-10	769.80	763.50	793	
Apr-10	905.06	502.70	906	
May-10	720.61	277.70	728	
Jun-10	557.38	142.70	553	
Jul-10	515.02	70.80	521	
Aug-10	515.88	119.60	524	
Sep-10	586.92	319.65	577	
Oct-10	652.64	516.80	657	
Nov-10	767.08	904.20	757	
Dec-10	981.60	1292.10	906	9082.35
Jan-11	1298.70	1201.00	1,315	
Feb-11	858.98	1004.60	831	
Mar-11	1010.89	1032.90	939	
Apr-11	723.10	587.50	695	
May-11	681.10	271.10	690	
Jun-11	612.67	143.10	608	
Jul-11	541.51	104.40	536	
Aug-11	590.46	195.10	573	
Sep-11	762.19	292.40	761	
Nov-11	651.97	511.90	658	
Nov-11	688.90	1059.10	624	
Dec-11	900.79	1006.30	925	9154.63
Jan-12	1186.89	1273.00	1,178	
Feb-12	898.98	935.50	895	
Mar-12	887.78	909.00	859	
Apr-12	712.02	512.60	710	
May-12	693.08	340.20	678	
Jun-12	486.72	149.70	480	
Jul-12	589.14	77.80	592	
Aug-12	593.11	134.00	597	
Sep-12	362.63	259.40	373	
Oct-12	628.62	714.50	563	
Nov-12	779.84	1112.80	696	
Dec-12	936.60	1356.20	838	8460.61
2013-F				8,899.2
2014-F				8,899.2
2015-F				8,899.2

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	997.90	1409.70	949	
Feb-98	652.96	942.00	648	
Mar-98	552.31	843.40	548	
Apr-98	563.65	500.10	566	
May-98	517.32	211.00	544	
Jun-98	448.82	89.00	461	
Jul-98	459.37	65.70	466	
Aug-98	493.96	156.80	490	
Sep-98	506.27	320.70	497	
Oct-98	554.50	561.20	544	
Nov-98	686.86	958.10	662	
Dec-98	694.52	1252.70	641	
Jan-99	908.00	1350.20	877	
Feb-99	683.08	1066.40	640	
Mar-99	608.71	871.40	596	
Apr-99	622.07	506.40	622	
May-99	501.75	372.20	479	
Jun-99	477.28	140.20	474	
Jul-99	467.05	99.40	463	
Aug-99	479.70	127.80	485	
Sep-99	482.08	292.50	481	
Oct-99	493.59	519.80	496	
Nov-99	739.99	939.90	720	
Dec-99	472.77	1013.00	492	
Jan-00	873.30	1344.80	844	
Feb-00	701.49	956.00	692	
Mar-00	554.63	750.10	578	
Apr-00	606.05	590.90	580	
May-00	547.08	373.80	524	
Jun-00	475.47	158.00	467	
Jul-00	464.64	84.30	466	
Aug-00	484.91	216.90	463	
Sep-00	534.36	314.80	527	
Oct-00	538.38	575.80	524	
Nov-00	591.77	858.40	597	
Dec-00	674.28	1222.80	630	
Jan-01	771.04	1043.40	833	
Feb-01	587.00	1031.00	555	
Mar-01	619.82	844.90	615	
Apr-01	487.01	535.80	478	
May-01	498.88	366.60	478	
Jun-01	481.64	155.50	474	
Jul-01	433.85	120.30	424	
Aug-01	452.74	120.60	460	
Sep-01	451.68	299.60	449	
Oct-01	506.50	577.00	492	
Nov-01	635.83	975.00	606	
Dec-01	694.04	1275.40	634	
Jan-02	745.25	1246.30	746	
Feb-02	714.61	970.30	701	
Mar-02	524.92	991.60	475	
Apr-02	580.34	694.80	523	
May-02	554.03	365.90	533	
Jun-02	417.79	147.80	412	
Jul-02	450.73	121.60	440	
Aug-02	462.56	181.50	451	
Sep-02	452.56	331.00	440	
Oct-02	555.52	514.80	560	
Nov-02	655.39	821.90	671	
Dec-02	586.84	1117.90	574	

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	813.99	1177.50	835	
Feb-03	652.99	964.70	641	
Mar-03	618.83	899.50	597	
Apr-03	618.90	554.40	604	
May-03	551.83	341.60	539	
Jun-03	476.52	179.90	461	
Jul-03	477.44	56.60	487	
Aug-03	494.15	163.00	488	
Sep-03	511.61	330.20	500	
Oct-03	498.63	526.10	499	
Nov-03	740.76	963.90	714	
Dec-03	735.28	1095.50	729	
Jan-04	1028.59	1365.60	993	
Feb-04	704.57	881.20	718	
Mar-04	635.33	809.90	641	
Apr-04	612.84	497.40	616	
May-04	505.48	292.30	507	
Jun-04	452.28	74.10	469	
Jul-04	487.09	35.60	503	
Aug-04	447.41	145.70	447	
Sep-04	522.56	370.70	498	
Oct-04	570.40	565.00	559	
Nov-04	617.92	875.50	618	
Dec-04	637.50	1070.70	639	
Jan-05	942.64	1330.30	918	
Feb-05	624.90	941.80	620	
Mar-05	567.46	726.90	598	
Apr-05	632.60	464.80	645	
May-05	481.28	256.90	494	
Jun-05	440.54	126.60	441	
Jul-05	466.05	136.90	451	
Aug-05	516.55	162.20	511	
Sep-05	585.49	297.30	583	
Oct-05	619.35	541.70	615	
Nov-05	692.66	758.40	728	
Dec-05	789.76	1061.00	794	
Jan-06	953.94	1185.20	973	
Feb-06	818.62	1016.70	791	
Mar-06	786.17	960.50	746	
Apr-06	714.89	528.20	708	
May-06	545.26	371.10	523	
Jun-06	515.27	136.50	513	
Jul-06	499.91	79.20	502	
Aug-06	454.73	171.70	446	
Sep-06	479.72	292.40	479	
Oct-06	613.82	543.30	609	
Nov-06	691.24	1196.20	594	
Dec-06	852.95	1050.00	861	
Jan-07	954.29	1102.40	998	
Feb-07	732.16	1017.30	704	
Mar-07	818.35	1001.90	766	
Apr-07	703.60	543.00	693	
May-07	523.82	332.20	513	
Jun-07	486.55	122.60	489	
Jul-07	494.65	88.60	494	
Aug-07	437.98	143.10	438	
Sep-07	506.63	314.70	499	
Oct-07	538.89	553.10	531	
Nov-07	666.59	956.60	642	
Dec-07	744.78	1255.10	690	

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1026.05	1300.10	1,010	
Feb-08	874.25	1064.20	832	
Mar-08	661.10	833.30	660	
Apr-08	750.33	554.00	736	
May-08	447.28	295.60	448	
Jun-08	490.71	191.00	472	
Jul-08	540.16	131.50	527	
Aug-08	523.79	154.00	521	
Sep-08	564.57	304.20	560	
Oct-08	622.52	523.50	624	
Nov-08	625.87	879.00	625	
Dec-08	730.65	1386.50	636	
Jan-09	1148.87	1329.30	1,124	
Feb-09	788.55	1089.50	739	
Mar-09	857.23	1054.20	789	
Apr-09	627.08	590.00	602	
May-09	697.31	356.00	680	
Jun-09	552.88	130.60	553	
Jul-09	480.71	89.00	480	
Aug-09	522.12	134.40	525	
Sep-09	529.64	279.40	533	
Oct-09	573.91	606.90	550	
Nov-09	700.62	996.50	664	
Dec-09	866.03	1273.66	806	
Jan-10	1036.85	1141.42	1,069	
Feb-10	742.83	965.80	730	
Mar-10	772.14	763.50	792	
Apr-10	645.62	502.70	647	
May-10	533.67	277.70	540	
Jun-10	568.32	142.70	564	
Jul-10	496.39	70.80	501	
Aug-10	501.36	119.60	509	
Sep-10	532.03	319.65	523	
Oct-10	654.48	516.80	658	
Nov-10	640.45	904.20	632	
Dec-10	747.00	1292.10	681	7846.17
Jan-11	987.48	1201.00	1,002	
Feb-11	726.69	1004.60	702	
Mar-11	859.42	1032.90	797	
Apr-11	604.34	587.50	580	
May-11	695.18	271.10	703	
Jun-11	498.84	143.10	495	
Jul-11	465.48	104.40	460	
Aug-11	526.94	195.10	511	
Sep-11	547.95	292.40	547	
Nov-11	602.00	511.90	607	
Nov-11	655.68	1059.10	600	
Dec-11	725.53	1006.30	747	7751.63
Jan-12	996.82	1273.00	989	
Feb-12	694.23	935.50	691	
Mar-12	720.61	909.00	696	
Apr-12	622.83	512.60	621	
May-12	582.21	340.20	569	
Jun-12	516.52	149.70	510	
Jul-12	463.71	77.80	467	
Aug-12	526.65	134.00	530	
Sep-12	530.57	259.40	540	
Oct-12	696.00	714.50	640	
Nov-12	747.74	1112.80	676	
Dec-12	921.21	1356.20	836	7764.49
2013-F				7,787.4
2014-F				7,787.4
2015-F				7,787.4

Yukon Electrical Company Limited
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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1053.77	1409.70	997	
Feb-98	768.05	942.00	762	
Mar-98	702.37	843.40	697	
Apr-98	707.15	500.10	709	
May-98	564.48	211.00	595	
Jun-98	527.32	89.00	541	
Jul-98	523.51	65.70	531	
Aug-98	538.05	156.80	534	
Sep-98	579.47	320.70	569	
Oct-98	663.64	561.20	652	
Nov-98	748.47	958.10	720	
Dec-98	871.31	1252.70	810	
Jan-99	984.21	1350.20	948	
Feb-99	788.10	1066.40	739	
Mar-99	744.40	871.40	729	
Apr-99	714.97	506.40	715	
May-99	630.60	372.20	605	
Jun-99	546.93	140.20	543	
Jul-99	526.49	99.40	522	
Aug-99	546.96	127.80	553	
Sep-99	624.58	292.50	624	
Oct-99	628.26	519.80	631	
Nov-99	766.42	939.90	744	
Dec-99	796.79	1013.00	819	
Jan-00	1138.54	1344.80	1,105	
Feb-00	893.65	956.00	883	
Mar-00	654.03	750.10	681	
Apr-00	703.14	590.90	674	
May-00	635.13	373.80	609	
Jun-00	558.33	158.00	548	
Jul-00	546.81	84.30	548	
Aug-00	588.65	216.90	563	
Sep-00	603.23	314.80	595	
Oct-00	663.78	575.80	647	
Nov-00	757.62	858.40	763	
Dec-00	971.14	1222.80	920	
Jan-01	931.65	1043.40	1,003	
Feb-01	812.83	1031.00	776	
Mar-01	726.99	844.90	721	
Apr-01	677.15	535.80	667	
May-01	651.81	366.60	628	
Jun-01	563.50	155.50	554	
Jul-01	537.78	120.30	526	
Aug-01	554.77	120.60	563	
Sep-01	547.25	299.60	544	
Oct-01	651.57	577.00	635	
Nov-01	792.98	975.00	758	
Dec-01	901.19	1275.40	832	
Jan-02	966.51	1246.30	967	
Feb-02	816.76	970.30	801	
Mar-02	725.43	991.60	668	
Apr-02	741.47	694.80	676	
May-02	641.83	365.90	618	
Jun-02	544.30	147.80	538	
Jul-02	542.23	121.60	530	
Aug-02	610.46	181.50	597	
Sep-02	557.53	331.00	543	
Oct-02	681.82	514.80	686	
Nov-02	762.41	821.90	781	
Dec-02	828.11	1117.90	813	

Yukon Electrical Company Limited
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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	947.50	1177.50	972	
Feb-03	770.27	964.70	756	
Mar-03	703.62	899.50	679	
Apr-03	773.76	554.40	757	
May-03	602.98	341.60	588	
Jun-03	555.94	179.90	538	
Jul-03	563.40	56.60	574	
Aug-03	548.69	163.00	542	
Sep-03	609.35	330.20	595	
Oct-03	649.46	526.10	650	
Nov-03	795.50	963.90	765	
Dec-03	968.04	1095.50	961	
Jan-04	971.82	1365.60	931	
Feb-04	807.08	881.20	822	
Mar-04	749.76	809.90	756	
Apr-04	746.11	497.40	749	
May-04	588.46	292.30	590	
Jun-04	605.37	74.10	625	
Jul-04	573.54	35.60	592	
Aug-04	565.49	145.70	565	
Sep-04	646.39	370.70	618	
Oct-04	650.27	565.00	637	
Nov-04	779.25	875.50	779	
Dec-04	897.31	1070.70	899	
Jan-05	1053.13	1330.30	1,024	
Feb-05	807.32	941.80	801	
Mar-05	746.25	726.90	782	
Apr-05	713.95	464.80	728	
May-05	627.27	256.90	642	
Jun-05	584.49	126.60	586	
Jul-05	550.97	136.90	534	
Aug-05	565.02	162.20	559	
Sep-05	689.66	297.30	687	
Oct-05	625.84	541.70	621	
Nov-05	735.46	758.40	776	
Dec-05	894.50	1061.00	900	
Jan-06	918.47	1185.20	940	
Feb-06	910.68	1016.70	879	
Mar-06	916.12	960.50	870	
Apr-06	725.57	528.20	718	
May-06	646.43	371.10	621	
Jun-06	577.76	136.50	575	
Jul-06	587.16	79.20	590	
Aug-06	577.82	171.70	568	
Sep-06	638.51	292.40	638	
Oct-06	664.22	543.30	659	
Nov-06	843.21	1196.20	731	
Dec-06	982.65	1050.00	992	
Jan-07	971.97	1102.40	1,022	
Feb-07	965.40	1017.30	933	
Mar-07	878.64	1001.90	818	
Apr-07	751.49	543.00	739	
May-07	690.20	332.20	678	
Jun-07	604.66	122.60	607	
Jul-07	563.42	88.60	563	
Aug-07	577.38	143.10	578	
Sep-07	586.28	314.70	578	
Oct-07	652.41	553.10	644	
Nov-07	843.28	956.60	815	
Dec-07	804.90	1255.10	742	

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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1123.44	1300.10	1,105	
Feb-08	1032.46	1064.20	984	
Mar-08	834.60	833.30	833	
Apr-08	763.84	554.00	747	
May-08	686.41	295.60	687	
Jun-08	567.13	191.00	546	
Jul-08	590.64	131.50	575	
Aug-08	597.43	154.00	594	
Sep-08	591.51	304.20	587	
Oct-08	660.28	523.50	662	
Nov-08	841.24	879.00	840	
Dec-08	931.20	1386.50	823	
Jan-09	1141.30	1329.30	1,113	
Feb-09	941.96	1089.50	885	
Mar-09	866.43	1054.20	788	
Apr-09	811.02	590.00	782	
May-09	661.27	356.00	641	
Jun-09	570.94	130.60	571	
Jul-09	600.87	89.00	600	
Aug-09	541.21	134.40	545	
Sep-09	622.45	279.40	626	
Oct-09	665.14	606.90	638	
Nov-09	780.80	996.50	738	
Dec-09	964.62	1273.66	896	
Jan-10	1092.76	1141.42	1,130	
Feb-10	861.27	965.80	847	
Mar-10	780.53	763.50	803	
Apr-10	758.96	502.70	760	
May-10	647.75	277.70	655	
Jun-10	582.47	142.70	578	
Jul-10	570.69	70.80	576	
Aug-10	528.80	119.60	537	
Sep-10	610.07	319.65	600	
Oct-10	735.74	516.80	740	
Nov-10	745.44	904.20	735	
Dec-10	912.11	1292.10	837	8797.87
Jan-11	1147.75	1201.00	1,164	
Feb-11	886.24	1004.60	858	
Mar-11	972.16	1032.90	901	
Apr-11	828.25	587.50	800	
May-11	682.17	271.10	691	
Jun-11	614.29	143.10	610	
Jul-11	546.69	104.40	541	
Aug-11	566.02	195.10	548	
Sep-11	642.19	292.40	641	
Nov-11	668.43	511.90	674	
Nov-11	794.53	1059.10	730	
Dec-11	924.66	1006.30	949	9107.89
Jan-12	1124.22	1273.00	1,115	
Feb-12	934.55	935.50	931	
Mar-12	865.63	909.00	837	
Apr-12	778.65	512.60	776	
May-12	710.36	340.20	696	
Jun-12	645.11	149.70	638	
Jul-12	588.63	77.80	592	
Aug-12	572.48	134.00	576	
Sep-12	564.38	259.40	575	
Oct-12	690.01	714.50	625	
Nov-12	773.48	1112.80	691	
Dec-12	1002.41	1356.20	905	8957.12
2013-F				8,954.3
2014-F				8,954.3
2015-F				8,954.3

Yukon Electrical Company Limited
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Keno City Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-98	384.70	1165.70	
Feb-98	458.92	719.10	
Mar-98	239.70	756.60	
Apr-98	289.27	458.60	
May-98	254.35	270.60	
Jun-98	244.49	119.50	
Jul-98	214.42	111.60	
Aug-98	299.18	189.20	
Sep-98	300.37	327.80	
Oct-98	363.74	557.70	
Nov-98	314.71	792.30	
Dec-98	244.83	1051.80	
Jan-99	359.97	1183.10	
Feb-99	300.66	976.40	
Mar-99	274.38	734.00	
Apr-99	328.53	508.80	
May-99	218.89	391.90	
Jun-99	207.66	153.90	
Jul-99	289.26	108.60	
Aug-99	310.03	145.70	
Sep-99	337.63	311.20	
Oct-99	369.92	499.80	
Nov-99	409.03	792.50	
Dec-99	270.84	844.00	
Jan-00	271.49	1082.90	
Feb-00	236.71	735.20	
Mar-00	230.17	659.20	
Apr-00	199.83	515.60	
May-00	256.57	382.00	
Jun-00	256.84	172.50	
Jul-00	250.86	142.10	
Aug-00	295.08	219.90	
Sep-00	283.24	354.20	
Oct-00	366.74	539.20	
Nov-00	283.16	691.20	
Dec-00	244.49	977.80	
Jan-01	275.53	722.70	
Feb-01	236.92	864.10	
Mar-01	287.54	765.30	
Apr-01	258.05	506.80	
May-01	273.66	390.40	
Jun-01	188.31	167.30	
Jul-01	290.95	139.60	
Aug-01	204.74	139.60	
Sep-01	243.29	309.00	
Oct-01	253.00	573.40	
Nov-01	235.97	818.00	
Dec-01	263.24	1094.60	
Jan-02	219.70	935.60	
Feb-02	190.70	824.60	
Mar-02	173.05	921.10	
Apr-02	199.70	653.30	
May-02	230.89	361.60	
Jun-02	210.37	175.60	
Jul-02	235.82	130.90	
Aug-02	264.55	182.80	
Sep-02	239.92	314.40	
Oct-02	250.49	444.30	
Nov-02	220.55	582.60	
Dec-02	220.37	845.20	

Yukon Electrical Company Limited
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Keno City Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-03	255.84	989.10	
Feb-03	204.08	756.60	
Mar-03	184.76	834.50	
Apr-03	177.39	514.30	
May-03	139.16	363.70	
Jun-03	157.24	192.80	
Jul-03	168.50	84.40	
Aug-03	167.61	180.60	
Sep-03	186.87	359.20	
Oct-03	166.74	466.70	
Nov-03	200.23	874.60	
Dec-03	239.89	911.60	
Jan-04	260.29	1257.90	
Feb-04	213.87	697.20	
Mar-04	192.89	753.50	
Apr-04	187.61	466.60	
May-04	187.61	272.50	
Jun-04	167.87	83.70	
Jul-04	156.95	74.20	
Aug-04	173.85	101.70	
Sep-04	222.10	367.50	
Oct-04	157.53	540.50	
Nov-04	274.74	719.80	
Dec-04	190.90	899.50	
Jan-05	246.31	1165.80	
Feb-05	250.95	795.20	
Mar-05	130.28	613.70	
Apr-05	114.58	453.30	
May-05	112.39	256.60	
Jun-05	119.93	154.40	
Jul-05	142.17	132.60	
Aug-05	202.78	150.80	
Sep-05	217.61	299.30	
Oct-05	156.34	534.60	
Nov-05	196.85	762.60	
Dec-05	194.88	794.40	
Jan-06	308.63	1096.20	
Feb-06	214.13	821.30	
Mar-06	296.58	906.30	
Apr-06	207.55	519.10	
May-06	165.68	346.90	
Jun-06	118.28	173.10	
Jul-06	147.02	118.40	
Aug-06	188.20	201.60	
Sep-06	223.71	295.70	
Oct-06	282.66	520.50	
Nov-06	326.76	1162.20	
Dec-06	336.86	824.30	
Jan-07	301.98	912.00	
Feb-07	247.56	998.80	
Mar-07	313.05	954.20	
Apr-07	232.98	511.90	
May-07	183.27	322.10	
Jun-07	159.59	140.50	
Jul-07	189.00	102.30	
Aug-07	218.21	154.20	
Sep-07	251.95	308.40	
Oct-07	327.39	543.70	
Nov-07	273.73	724.60	
Dec-07	223.00	1069.50	

Yukon Electrical Company Limited
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Keno City

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	260.59	1113.80	
Feb-08	308.00	954.60	
Mar-08	233.90	734.70	
Apr-08	304.18	517.30	
May-08	213.00	307.90	
Jun-08	144.85	225.60	
Jul-08	173.07	173.40	
Aug-08	276.17	187.70	
Sep-08	419.12	318.70	
Oct-08	397.65	563.00	
Nov-08	412.73	782.50	
Dec-08	576.50	1186.20	
Jan-09	659.73	1137.90	
Feb-09	294.60	955.40	
Mar-09	568.74	868.50	
Apr-09	323.17	515.20	
May-09	247.26	331.20	
Jun-09	177.57	144.10	
Jul-09	186.95	62.50	
Aug-09	180.45	158.30	
Sep-09	251.31	306.10	
Oct-09	295.00	541.80	
Nov-09	360.00	781.50	
Dec-09	383.54	943.40	
Jan-10	396.90	991.10	
Feb-10	332.03	679.20	
Mar-10	417.27	656.00	
Apr-10	343.62	461.20	
May-10	368.00	292.00	
Jun-10	127.73	171.90	
Jul-10	184.69	117.30	
Aug-10	200.71	146.20	
Sep-10	427.00	332.40	
Oct-10	445.68	520.40	
Nov-10	572.14	717.60	
Dec-10	574.70	1162.50	4390.45
Jan-11	588.16	1010.20	
Feb-11	431.76	905.60	
Mar-11	608.84	901.70	
Apr-11	341.70	511.20	
May-11	342.41	296.20	
Jun-11	229.43	161.00	
Jul-11	335.75	127.80	
Aug-11	140.25	217.90	
Sep-11	343.23	328.50	
Nov-11	447.10	513.30	
Nov-11	471.67	936.25	
Dec-11	640.79	775.10	4921.08
Jan-12	359.21	1118.10	
Feb-12	405.82	707.50	
Mar-12	467.28	756.20	
Apr-12	396.59	450.60	
May-12	381.95	350.80	
Jun-12	293.30	200.00	
Jul-12	198.71	140.10	
Aug-12	220.54	157.90	
Sep-12	332.27	287.15	
Oct-12	458.27	631.40	
Nov-12	566.32	969.60	
Dec-12	480.71	1196.80	4560.95
2013-F			4,624.2
2014-F			4,624.2
2015-F			4,624.2

Yukon Electrical Company Limited
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Stewart Crossing Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Annual UPC (kWh)
Jan-98	570.00	1409.70	
Feb-98	418.18	942.00	
Mar-98	376.09	843.40	
Apr-98	296.58	500.10	
May-98	387.67	211.00	
Jun-98	274.58	89.00	
Jul-98	350.92	65.70	
Aug-98	347.67	156.80	
Sep-98	343.92	320.70	
Oct-98	403.31	561.20	
Nov-98	454.86	958.10	
Dec-98	587.07	1252.70	
Jan-99	1042.80	1350.20	
Feb-99	719.20	1066.40	
Mar-99	511.07	871.40	
Apr-99	510.33	506.40	
May-99	419.27	372.20	
Jun-99	373.13	140.20	
Jul-99	437.13	99.40	
Aug-99	350.67	127.80	
Sep-99	460.07	292.50	
Oct-99	364.87	519.80	
Nov-99	472.67	939.90	
Dec-99	493.00	1013.00	
Jan-00	880.87	1344.80	
Feb-00	432.40	956.00	
Mar-00	421.80	750.10	
Apr-00	473.80	590.90	
May-00	336.87	373.80	
Jun-00	348.40	158.00	
Jul-00	335.07	84.30	
Aug-00	336.67	216.90	
Sep-00	495.75	314.80	
Oct-00	462.19	575.80	
Nov-00	689.63	858.40	
Dec-00	505.06	1222.80	
Jan-01	589.41	1043.40	
Feb-01	469.00	1031.00	
Mar-01	659.65	844.90	
Apr-01	393.75	535.80	
May-01	536.25	366.60	
Jun-01	284.31	155.50	
Jul-01	302.75	120.30	
Aug-01	310.13	120.60	
Sep-01	486.20	299.60	
Oct-01	449.13	577.00	
Nov-01	749.47	975.00	
Dec-01	606.47	1275.40	
Jan-02	605.94	1246.30	
Feb-02	673.69	970.30	
Mar-02	482.06	991.60	
Apr-02	531.94	694.80	
May-02	647.00	365.90	
Jun-02	482.81	147.80	
Jul-02	469.19	121.60	
Aug-02	569.31	181.50	
Sep-02	503.93	331.00	
Oct-02	667.60	514.80	
Nov-02	634.07	821.90	
Dec-02	842.20	1117.90	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Stewart Crossing Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Annual UPC (kWh)
Jan-03	1071.73	1177.50	
Feb-03	853.33	964.70	
Mar-03	783.20	899.50	
Apr-03	760.60	554.40	
May-03	693.53	341.60	
Jun-03	535.40	179.90	
Jul-03	700.93	56.60	
Aug-03	534.20	163.00	
Sep-03	631.67	330.20	
Oct-03	726.13	526.10	
Nov-03	708.53	963.90	
Dec-03	950.60	1095.50	
Jan-04	1042.00	1365.60	
Feb-04	683.07	881.20	
Mar-04	704.87	809.90	
Apr-04	835.33	497.40	
May-04	640.53	292.30	
Jun-04	651.93	74.10	
Jul-04	729.67	35.60	
Aug-04	598.13	145.70	
Sep-04	605.60	370.70	
Oct-04	837.20	565.00	
Nov-04	850.33	875.50	
Dec-04	663.27	1070.70	
Jan-05	1209.73	1330.30	
Feb-05	891.20	941.80	
Mar-05	716.13	726.90	
Apr-05	899.67	464.80	
May-05	598.80	256.90	
Jun-05	710.60	126.60	
Jul-05	617.40	136.90	
Aug-05	664.07	162.20	
Sep-05	731.60	297.30	
Oct-05	682.13	541.70	
Nov-05	720.27	758.40	
Dec-05	829.80	1061.00	
Jan-06	1086.00	1185.20	
Feb-06	947.62	1016.70	
Mar-06	990.60	960.50	
Apr-06	633.33	528.20	
May-06	632.43	371.10	
Jun-06	831.31	136.50	
Jul-06	561.29	79.20	
Aug-06	817.07	171.70	
Sep-06	940.93	292.40	
Oct-06	821.71	543.30	
Nov-06	888.57	1196.20	
Dec-06	1078.14	1050.00	
Jan-07	1226.93	1102.40	
Feb-07	1030.27	1017.30	
Mar-07	1290.67	1001.90	
Apr-07	693.38	543.00	
May-07	610.25	332.20	
Jun-07	624.94	122.60	
Jul-07	540.75	88.60	
Aug-07	635.69	143.10	
Sep-07	629.63	314.70	
Oct-07	626.19	553.10	
Nov-07	783.25	956.60	
Dec-07	577.63	1255.10	

Yukon Electrical Company Limited
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Stewart Crossing

Residential		(Watson Lake)	Annual
monthly	UPC (kWh)	MHDD	UPC (kWh)
Jan-08	1085.56	1300.10	
Feb-08	873.31	1064.20	
Mar-08	897.88	833.30	
Apr-08	422.19	554.00	
May-08	547.94	295.60	
Jun-08	532.81	191.00	
Jul-08	300.06	131.50	
Aug-08	641.31	154.00	
Sep-08	467.19	304.20	
Oct-08	707.38	523.50	
Nov-08	624.38	879.00	
Dec-08	724.44	1386.50	
Jan-09	1134.44	1329.30	
Feb-09	978.07	1089.50	
Mar-09	671.81	1054.20	
Apr-09	842.37	590.00	
May-09	542.81	356.00	
Jun-09	490.81	130.60	
Jul-09	629.67	89.00	
Aug-09	618.31	134.40	
Sep-09	641.93	279.40	
Oct-09	621.40	606.90	
Nov-09	682.31	996.50	
Dec-09	711.63	1273.66	
Jan-10	1036.07	1141.42	
Feb-10	667.33	965.80	
Mar-10	700.20	763.50	
Apr-10	662.79	502.70	
May-10	603.20	277.70	
Jun-10	412.60	142.70	
Jul-10	492.53	70.80	
Aug-10	446.07	119.60	
Sep-10	544.86	319.65	
Oct-10	312.47	516.80	
Nov-10	785.87	904.20	
Dec-10	817.27	1292.10	7481.24
Jan-11	1152.57	1201.00	
Feb-11	846.53	1004.60	
Mar-11	845.87	1032.90	
Apr-11	790.93	587.50	
May-11	880.31	271.10	
Jun-11	343.00	143.10	
Jul-11	718.36	104.40	
Aug-11	524.40	195.10	
Sep-11	602.80	292.40	
Nov-11	558.20	511.90	
Nov-11	671.00	1059.10	
Dec-11	807.25	1006.30	8741.22
Jan-12	1280.50	1273.00	
Feb-12	775.50	935.50	
Mar-12	850.29	909.00	
Apr-12	431.71	512.60	
May-12	570.36	340.20	
Jun-12	625.69	149.70	
Jul-12	466.57	77.80	
Aug-12	603.57	134.00	
Sep-12	443.14	259.40	
Oct-12	516.07	714.50	
Nov-12	1002.92	1112.80	
Dec-12	1001.85	1356.20	8568.18
2013-F		1,218	8,263.5
2014-F		1,218	8,263.5
2015-F		1,218	8,263.5

Yukon Electrical Company Limited
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Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-98	1148.33	1165.70	
Feb-98	1390.67	719.10	
Mar-98	1251.00	756.60	
Apr-98	1103.67	458.60	
May-98	945.67	270.60	
Jun-98	861.00	119.50	
Jul-98	625.67	111.60	
Aug-98	1008.33	189.20	
Sep-98	1095.00	327.80	
Oct-98	935.33	557.70	
Nov-98	1137.00	792.30	
Dec-98	931.67	1051.80	
Jan-99	974.67	1183.10	
Feb-99	2270.33	976.40	
Mar-99	1260.67	734.00	
Apr-99	970.33	508.80	
May-99	1263.00	391.90	
Jun-99	830.00	153.90	
Jul-99	897.00	108.60	
Aug-99	817.00	145.70	
Sep-99	989.67	311.20	
Oct-99	1007.67	499.80	
Nov-99	1168.33	792.50	
Dec-99	1039.67	844.00	
Jan-00	1437.67	1082.90	
Feb-00	1334.00	735.20	
Mar-00	1228.33	659.20	
Apr-00	1005.33	515.60	
May-00	1066.67	382.00	
Jun-00	909.67	172.50	
Jul-00	840.00	142.10	
Aug-00	979.67	219.90	
Sep-00	857.67	354.20	
Oct-00	1044.67	539.20	
Nov-00	1111.33	691.20	
Dec-00	1285.33	977.80	
Jan-01	1344.67	722.70	
Feb-01	1051.67	864.10	
Mar-01	1105.00	765.30	
Apr-01	1138.33	506.80	
May-01	995.33	390.40	
Jun-01	852.67	167.30	
Jul-01	910.00	139.60	
Aug-01	1008.67	139.60	
Sep-01	997.33	309.00	
Oct-01	1231.33	573.40	
Nov-01	1093.33	818.00	
Dec-01	1126.33	1094.60	
Jan-02	1300.33	935.60	
Feb-02	1052.00	824.60	
Mar-02	1169.67	921.10	
Apr-02	1142.00	653.30	
May-02	1029.33	361.60	
Jun-02	810.67	175.60	
Jul-02	878.67	130.90	
Aug-02	1053.67	182.80	
Sep-02	1013.67	314.40	
Oct-02	1040.00	444.30	
Nov-02	1074.67	582.60	
Dec-02	1034.00	845.20	

Yukon Electrical Company Limited
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Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-03	1562.00	989.10	
Feb-03	1149.67	756.60	
Mar-03	1183.33	834.50	
Apr-03	1727.33	514.30	
May-03	1079.33	363.70	
Jun-03	940.00	192.80	
Jul-03	713.33	84.40	
Aug-03	995.33	180.60	
Sep-03	979.00	359.20	
Oct-03	1003.67	466.70	
Nov-03	1087.00	874.60	
Dec-03	1379.67	911.60	
Jan-04	1503.00	1257.90	
Feb-04	1325.33	697.20	
Mar-04	660.33	753.50	
Apr-04	1102.67	466.60	
May-04	915.00	272.50	
Jun-04	964.67	83.70	
Jul-04	938.33	74.20	
Aug-04	936.33	101.70	
Sep-04	970.67	367.50	
Oct-04	1082.67	540.50	
Nov-04	1215.00	719.80	
Dec-04	1083.00	899.50	
Jan-05	1430.67	1165.80	
Feb-05	1177.33	795.20	
Mar-05	891.67	613.70	
Apr-05	991.67	453.30	
May-05	659.33	256.60	
Jun-05	1585.00	154.40	
Jul-05	904.67	132.60	
Aug-05	932.67	150.80	
Sep-05	894.00	299.30	
Oct-05	1050.67	534.60	
Nov-05	1142.33	762.60	
Dec-05	1240.00	794.40	
Jan-06	1113.33	1096.20	
Feb-06	1596.33	821.30	
Mar-06	1869.67	906.30	
Apr-06	1351.67	519.10	
May-06	1412.67	346.90	
Jun-06	979.00	173.10	
Jul-06	871.00	118.40	
Aug-06	911.67	201.60	
Sep-06	1007.33	295.70	
Oct-06	1077.00	520.50	
Nov-06	1236.00	1162.20	
Dec-06	1497.67	824.30	
Jan-07	1829.67	912.00	
Feb-07	1563.67	998.80	
Mar-07	1426.00	954.20	
Apr-07	1210.00	511.90	
May-07	1262.33	322.10	
Jun-07	1116.00	140.50	
Jul-07	1491.67	102.30	
Aug-07	639.67	154.20	
Sep-07	879.33	308.40	
Oct-07	979.33	543.70	
Nov-07	1180.00	724.60	
Dec-07	1136.00	1069.50	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	1438.67	1113.80	
Feb-08	1381.33	954.60	
Mar-08	1053.33	734.70	
Apr-08	1539.00	517.30	
May-08	666.67	307.90	
Jun-08	711.00	225.60	
Jul-08	798.33	173.40	
Aug-08	711.67	187.70	
Sep-08	791.67	318.70	
Oct-08	851.67	563.00	
Nov-08	1001.67	782.50	
Dec-08	1205.33	1186.20	
Jan-09	1811.67	1137.90	
Feb-09	1290.33	955.40	
Mar-09	1636.33	868.50	
Apr-09	1408.00	515.20	
May-09	1376.00	331.20	
Jun-09	1203.33	144.10	
Jul-09	1127.67	62.50	
Aug-09	1108.00	158.30	
Sep-09	1143.33	306.10	
Oct-09	820.00	541.80	
Nov-09	820.00	781.50	
Dec-09	833.33	943.40	
Jan-10	1014.50	991.10	
Feb-10	860.00	679.20	
Mar-10	809.50	656.00	
Apr-10	780.00	461.20	
May-10	464.25	292.00	
Jun-10	309.50	171.90	
Jul-10	123.00	117.30	
Aug-10	525.00	146.20	
Sep-10	567.00	332.40	
Oct-10	451.50	520.40	
Nov-10	1050.00	717.60	
Dec-10	1556.50	1162.50	8510.75
Jan-11	1613.00	1010.20	
Feb-11	1036.00	905.60	
Mar-11	1043.50	901.70	
Apr-11	1853.50	511.20	
May-11	751.00	296.20	
Jun-11	564.50	161.00	
Jul-11	530.50	127.80	
Aug-11	654.50	217.90	
Sep-11	640.50	328.50	
Nov-11	833.00	513.30	
Nov-11	1137.50	936.25	
Dec-11	1126.00	775.10	11783.50
Jan-12	1425.50	1118.10	
Feb-12	1153.50	707.50	
Mar-12	1031.00	756.20	
Apr-12	1014.00	450.60	
May-12	-1357.00	350.80	
Jun-12	869.50	200.00	
Jul-12	743.50	140.10	
Aug-12	774.00	157.90	
Sep-12	804.00	287.15	
Oct-12	671.50	631.40	
Nov-12	1030.50	969.60	
Dec-12	892.50	1196.80	9052.50
2013-F		1,045	9,782.3
2014-F		1,045	9,782.3
2015-F		1,045	9,782.3

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Watson Lake
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	930.6	1,266.0	938.7	1,605.2	1,406.6	1,409.7	1,350.2	1,344.8	1,043.4	1,246.3	1,177.5	1,365.6	1,330.3	1,185.2	1,102.4	1,300.1	1,329.3	1,141.4	1,201.0	1,273.0	**1,247.4**
FEB	752.4	119.4	941.9	947.3	884.8	942.0	1,066.4	956.0	1,031.0	970.3	964.7	881.2	941.8	1,016.7	1,017.3	1,064.2	1,089.5	965.8	1,004.6	935.5	**924.6**
MAR	573.0	24.3	855.6	874.3	943.9	843.4	871.4	750.1	844.9	991.6	899.5	809.9	726.9	960.5	1,001.9	833.3	1,054.2	763.5	1,032.9	909.0	**828.2**
APR	347.3	50.1	492.7	547.7	527.9	500.1	506.4	590.9	535.8	694.8	554.4	497.4	464.8	528.2	543.0	554.0	590.0	502.7	587.5	512.6	**506.4**
MAY	190.5	21.8	242.5	366.4	311.8	211.0	372.2	373.8	366.6	365.9	341.6	292.3	256.9	371.1	332.2	295.6	356.0	277.7	271.1	340.2	**297.9**
JUN	99.2	0.8	97.0	163.9	142.6	89.0	140.2	158.0	155.5	147.8	179.9	74.1	126.6	136.5	122.6	191.0	130.6	142.7	143.1	149.7	**129.5**
JUL	83.2	1.2	113.0	103.3	84.1	65.7	99.4	84.3	120.3	121.6	56.6	35.6	136.9	79.2	88.6	131.5	89.0	70.8	104.4	77.8	**87.3**
AUG	66.0	2.3	189.9	185.1	109.6	156.8	127.8	216.9	120.6	181.5	163.0	145.7	162.2	171.7	143.1	154.0	134.4	119.6	195.1	134.0	**144.0**
SEP	298.4	38.8	224.9	354.7	271.1	320.7	292.5	314.8	299.6	331.0	330.2	370.7	297.3	292.4	314.7	304.2	279.4	319.7	292.4	259.4	**290.3**
OCT	248.2	89.8	552.7	662.2	659.7	561.2	519.8	575.8	577.0	514.8	526.1	565.0	541.7	543.3	553.1	523.5	606.9	516.8	511.9	714.5	**528.2**
NOV	127.3	59.4	1,000.2	1,121.2	935.8	958.1	939.9	858.4	975.0	821.9	963.9	875.5	758.4	1,196.2	956.6	879.0	996.5	904.2	1,059.1	1,112.8	**875.0**
DEC	22.1	122.5	1,295.4	1,361.1	983.7	1,252.7	1,013.0	1,222.8	1,275.4	1,117.9	1,095.5	1,070.7	1,061.0	1,050.0	1,255.1	1,386.5	1,273.7	1,292.1	1,006.3	1,356.2	**1,075.7**
TOTAL	**3,738.2**	**1,796.4**	**6,944.5**	**8,292.4**	**7,261.6**	**7,310.4**	**7,299.2**	**7,446.6**	**7,345.1**	**7,505.4**	**7,252.9**	**6,983.7**	**6,804.8**	**7,531.0**	**7,430.6**	**7,616.9**	**7,929.5**	**7,017.0**	**7,409.4**	**7,774.7**	**6,934.5**

Residential Regression Results (YECL 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

Residential (Carmacks)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.848334198
R Square	0.719670911
Adjusted R Square	0.718096029
Standard Error	137.0322957
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8580876.545	8580876.545	456.9679975	4.88748E-51
Residual	178	3342457.313	18777.85007		
Total	179	11923333.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	523.0507986	19.82511653	26.38323956	2.06292E-63	483.9282934	562.1733039	483.9282934	562.1733039
WH-HDD	0.66162154	0.030950434	21.37680981	4.88748E-51	0.600544547	0.722698534	0.600544547	0.722698534

Residential (Carcross)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.73085291
R Square	0.534145976
Adjusted R Square	0.531528819
Standard Error	100.3552824
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2055467.372	2055467.372	204.0939414	2.42352E-31
Residual	178	1792670.521	10071.1827		
Total	179	3848137.893			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	419.1099542	14.51887788	28.86655275	4.6941E-69	390.4586787	447.7612298	390.4586787	447.7612298
WH-HDD	0.323816596	0.022666478	14.28614509	2.42352E-31	0.279087002	0.36854619	0.279087002	0.36854619

Residential (Haines Junction)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.826511766
R Square	0.683121699
Adjusted R Square	0.681341483
Standard Error	70.97827216
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1933198.401	1933198.401	383.7298477	2.73648E-46
Residual	178	896748.8911	5037.915119		
Total	179	2829947.292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	493.5031661	10.26876554	48.0586653	7.1519E-104	473.2389809	513.7673514	473.2389809	513.7673514
WH-HDD	0.31403787	0.016031318	19.58902365	2.73648E-46	0.282401974	0.345673766	0.282401974	0.345673766

Residential (Teslin)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.774809495
R Square	0.600329753
Adjusted R Square	0.598084415
Standard Error	80.08503489
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1714789.401	1714789.401	267.3671534	2.73398E-37
Residual	178	1141623.081	6413.612813		
Total	179	2856412.482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	401.3105811	11.58628439	34.63669349	5.10981E-81	378.4464294	424.1747328	378.4464294	424.1747328
WH-HDD	0.295766652	0.018088193	16.35136549	2.73398E-37	0.260071758	0.331461545	0.260071758	0.331461545

Residential (Ross River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.816954541
R Square	0.667414722
Adjusted R Square	0.665546265
Standard Error	99.84467893
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3560923.245	3560923.245	357.2010799	2.05162E-44
Residual	178	1774474.864	9968.959911		
Total	179	5335398.109			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	420.6644462	14.44500644	29.12179014	1.28614E-69	392.1589471	449.1699452	392.1589471	449.1699452
WH-HDD	0.426211453	0.022551152	18.89976402	2.05162E-44	0.381709441	0.470713465	0.381709441	0.470713465

Residential (Pelly Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.814590942
R Square	0.663558403
Adjusted R Square	0.661668282
Standard Error	106.1935622
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3959003.162	3959003.162	351.0665651	5.74021E-44
Residual	178	2007318.933	11277.07266		
Total	179	5966322.096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	526.6014045	15.3635297	34.27606902	2.58572E-80	496.2833092	556.9194997	496.2833092	556.9194997
WH-HDD	0.449403793	0.023985126	18.7367704	5.74021E-44	0.402072005	0.496735581	0.402072005	0.496735581

Residential (Old Crow)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.700799321
R Square	0.491119688
Adjusted R Square	0.48826081
Standard Error	91.97982219
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1453372.136	1453372.136	171.7875549	6.55924E-28
Residual	178	1505931.209	8460.28769		
Total	179	2959303.345			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	431.2915805	13.30716006	32.41049018	1.39504E-76	405.0314857	457.5516753	405.0314857	457.5516753
WH-HDD	0.272290334	0.020774777	13.10677515	6.55924E-28	0.231293786	0.313286881	0.231293786	0.313286881

Residential (Destruction Bay)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.709031239
R Square	0.502725298
Adjusted R Square	0.49993162
Standard Error	72.69183708
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	950879.8973	950879.8973	179.9510466	8.32101E-29
Residual	178	940570.3656	5284.103178		
Total	179	1891450.263			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	383.8946	10.51667516	36.50341902	1.40822E-84	363.1411947	404.6480054	363.1411947	404.6480054
WH-HDD	0.220245296	0.016418348	13.41458336	8.32101E-29	0.187845643	0.25264495	0.187845643	0.25264495

Residential (Beaver Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.840637508
R Square	0.706671419
Adjusted R Square	0.705023506
Standard Error	87.03187359
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3248177.952	3248177.952	428.8280135	2.78648E-49
Residual	178	1348269.37	7574.547021		
Total	179	4596447.322			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	483.8810515	12.59131671	38.4297419	4.15449E-88	459.0335882	508.7285147	459.0335882	508.7285147
WH-HDD	0.407064957	0.019657222	20.70816297	2.78648E-49	0.368273771	0.445856142	0.368273771	0.445856142

Residential (Tagish)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77755681
R Square	0.604594592
Adjusted R Square	0.602373213
Standard Error	63.68762658
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1103956.052	1103956.052	272.1708788	1.04861E-37
Residual	178	721988.2526	4056.113779		
Total	179	1825944.304			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	234.2954311	9.213993033	25.42821883	3.71752E-61	216.1127137	252.4781485	216.1127137	252.4781485
WH-HDD	0.237312001	0.014384636	16.49760221	1.04861E-37	0.208925636	0.265698366	0.208925636	0.265698366

Residential (Marsh Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.873151604
R Square	0.762393723
Adjusted R Square	0.761058856
Standard Error	88.06938915
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4429873.997	4429873.997	571.1384587	1.93035E-57
Residual	178	1380606.68	7756.217305		
Total	179	5810480.677			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	386.6155856	12.74141904	30.3432125	2.9027E-72	361.4719133	411.7592579	361.4719133	411.7592579
WH-HDD	0.475378456	0.019891558	23.89850327	1.93035E-57	0.436124837	0.514632075	0.436124837	0.514632075

Residential (Deep Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.752248092
R Square	0.565877192
Adjusted R Square	0.5634383
Standard Error	105.7520673
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2594820.496	2594820.496	232.0222255	4.42027E-34
Residual	178	1990662.952	11183.49973		
Total	179	4585483.448			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	248.7081064	15.29965652	16.25579673	5.11914E-37	218.5160572	278.9001555	218.5160572	278.9001555
WH-HDD	0.363829131	0.023885409	15.23227578	4.42027E-34	0.316694123	0.410964139	0.316694123	0.410964139

Residential (Lower Post BC)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.81614908
R Square	0.666099321
Adjusted R Square	0.664223475
Standard Error	102.4652481
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3728162.932	3728162.932	355.0926572	2.91803E-44
Residual	178	1868844.62	10499.12708		
Total	179	5597007.552			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	482.5359337	13.76104774	35.06534841	7.55861E-82	455.3801456	509.6917217	455.3801456	509.6917217
WL-HDD	0.350883145	0.018620514	18.84390239	2.91803E-44	0.31413778	0.387628511	0.31413778	0.387628511

Residential (Upper Liard)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.837904563
R Square	0.702084057
Adjusted R Square	0.700410372
Standard Error	81.41823385
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2780729.358	2780729.358	419.483968	1.11237E-48
Residual	178	1179949.327	6628.928803		
Total	179	3960678.685			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	434.4074757	10.93444093	39.72836641	2.07109E-90	412.8296594	455.9852921	412.8296594	455.9852921
WL-HDD	0.303036141	0.014795742	20.48130777	1.11237E-48	0.273838507	0.332233774	0.273838507	0.332233774

Residential (Watson Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91758524
R Square	0.841962672
Adjusted R Square	0.841074822
Standard Error	62.27248406
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3677439.547	3677439.547	948.3161829	3.18151E-73
Residual	178	690259.4843	3877.862272		
Total	179	4367699.032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	515.255402	8.36317329	61.61003535	5.5467E-122	498.7516761	531.759128	498.7516761	531.759128
WL-HDD	0.348488007	0.011316477	30.79474278	3.18151E-73	0.326156287	0.370819726	0.326156287	0.370819726

Residential (Keno City)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.45197141
R Square	0.204278155
Adjusted R Square	0.199807808
Standard Error	98.54936507
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	443801.0337	443801.0337	45.69625911	1.90467E-10
Residual	178	1728731.969	9711.977356		
Total	179	2172533.003			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	195.761055	14.2576072	13.73028813	1.00194E-29	167.625366	223.8967439	167.625366	223.8967439
WH-HDD	0.150465857	0.022258589	6.759900821	1.90467E-10	0.106541183	0.194390532	0.106541183	0.194390532

Residential (Stewart Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.578269149
R Square	0.334395209
Adjusted R Square	0.330655856
Standard Error	179.1744974
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2870886.34	2870886.34	89.4259596	1.88615E-17
Residual	178	5714423.091	32103.50051		
Total	179	8585309.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	462.7767125	24.06307365	19.23182047	2.54602E-45	415.2911039	510.2623212	415.2911039	510.2623212
WL-HDD	0.307909483	0.032560515	9.456529998	1.88615E-17	0.243655187	0.372163779	0.243655187	0.372163779

Residential (Swift River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.478815384
R Square	0.229264172
Adjusted R Square	0.224934195
Standard Error	309.1635718
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5060894.424	5060894.424	52.9481323	1.05385E-11
Residual	178	17013616.31	95582.11413		
Total	179	22074510.74			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	774.2960938	44.72817013	17.3111507	5.25351E-40	686.0303795	862.5618081	686.0303795	862.5618081
WH-HDD	0.508109656	0.069828406	7.276546729	1.05385E-11	0.370311618	0.645907694	0.370311618	0.645907694

YUB-YECL-80

Reference: Depreciation, YECL Application, page 7-1

The depreciation rates used to calculate actual 2008 through 2012 depreciation expense were developed using the Board-approved depreciation parameters form Yukon Electrical's last General Rate Application.

Request:

(a) Please provide the terms of reference and the direction given by YECL to Gannett Fleming Inc. to undertake and the need for the depreciation study.

(b) Why is there a need to change YECL's depreciation study?

Response:

(a) Gannett Fleming was retained by Yukon Electrical in November 2012 to complete a full and comprehensive depreciation study. Gannett Fleming was also asked to research and provide an assessment of the reasonableness of including a request for the re-instatement of net salvage percentages into the depreciation rate calculations. There were no formal contractual documents or terms of reference.

(b) As stated in YUB-YECL-88(a), depreciation studies are typically completed every 3 to 5 years. Yukon Electrical's last depreciation study was submitted in its 2008-2009 GTA and was based upon data as of December 31, 2007. Yukon Electrical's submitted depreciation study is based upon data as of December 31, 2011. As detailed in Yukon Electrical's 2008-2009 GTA, Schedule 8.5, line 2, the 2007 year-end balance was $117M. As detailed in Yukon Electrical's current GTA, Schedule 8.5, line 2, the 2011 year-end balance was $155M with the 2015 year-end balance expected to be $229M. This represents an approximate 32% increase in property, plant and equipment from the 2007 data represented in Yukon Electrical's last depreciation study to the 2011 data represented in Yukon Electrical's current depreciation study. Furthermore, the year-end balance as of 2015 represents approximately a 96% increase from the 2007 year-end balance. In light of this significant amount of capital activity, Yukon Electrical determined that a detailed review and study was necessary to ensure an accurate recovery of its capital assets.

In addition, as detailed in Section 7, page 7-1, lines 10-14, Yukon Electrical is proposing to change the method of depreciation for diesel generation from a mass property approach to a life span approach. This change will allow for more accurate diesel generation depreciation rates.

In addition to the above noted issue driving the need for the depreciation study, Yukon Electrical also believes it is important for all parties to understand the following broader picture changes that have occurred in the Yukon since Board Order 2009-02.

The first issue that has changed since Board Order 2009-02 is that sending the right price signal to customers has taken on added importance as a result of diesel generation once again being on the margin in the Yukon. As the Board is aware, price signals that reflect the full cost to serve customers were discussed as part of the 2010 Yukon Electrical and Yukon Energy Joint Phase II Rate Application. While a large amount of the rate design discussion centered on economy and efficiency principles within the rate design of runoff rates and what exactly was meant by the term "economy and efficiency", Yukon Electrical notes the following statements in Board Order 2010-13 (paragraphs 196-197):

> The Board has considered the views of all the Parties and notes that there clearly is no consensus on this issue. However, it is clear that the Companies agree that in the past, economy and efficiency has been linked to the incremental cost of diesel generation.
>
> In terms of pricing signals, the Board is of the view that the best pricing signals to customers are those prices that reflect the full cost to serve those customers. Arguments on incremental cost of diesel generation, or what portion of the incremental cost of diesel generation should be reflected in the runoff rates should take a distant backseat to the proper alignment of costs to revenues for each rate class. Once rebalancing has occurred for the rate classes, then issues relating to runoff can be examined in greater detail.

While Yukon Electrical recognizes the above statements were in the context of setting runoff rates, it is for this exact reason of prices reflecting the full cost to serve customer that Yukon Electrical is requesting to once again collect negative net salvage as part of its revenue requirement.

A second large change since Board Order 2009-02 has been the development and inclusion in this Application of the Joint Yukon Electrical and Yukon Energy Demand Side Management (DSM) program. This program will promote energy conservation and will result in lower energy consumption. It is Yukon Electrical's position that it is counter intuitive to be investing in this DSM program while, at the same time, not sending the right price signal by not fully charging current customers for the cost to provide electric service; namely the cost associated with net salvage.

A third large change since Board Order 2009-02 has been the cessation of collection of net salvage resulting in Yukon Electrical falling considerably behind in its required recovery of the funds for future removal of assets. In the 3 year period from 2009 through 2011, an increase in the amount of Future Removal and Site Restoration (i.e. FRSR) deficiency transfer from current users of the Yukon Electrical utility assets to future rate-payers of $7.9 million has accrued to a total balance of over $12 million. It is noted that this significant increase in transfer to future rate-payers is caused by two significant forces. Firstly, the retirement costs associated with assets that have retired over the past 3 year period have drawn down the FRSR by over 6.2%[1] of the balance that existed at December 31, 2008. However, this draw down of the FRSR was caused by retirements of only approximately 3% of the plant in service as at December 2008[2]. In other words, the FRSR balance is drawing down at approximately twice the rate of the asset retirement activity of the plant in service balance that existed at December 31, 2008.

The second cause of the significant increase in the accumulated FRSR deficiency is the fact that older vintages of assets are now 3 years closer to expected retirement, providing less time for these vintages to recover the FRSR deficiency. While approximately 3% of the investment in plant in service as of 2008 has retired over the period from 2009 through 2011, this pace of retirements is expected to significantly increase in future years, which will require significantly increased amounts of cost of removal funding. For example, over the past 16 years, 4 diesel generating units have been removed and retired from service. However, over the next 3 year period 7 units will require replacement due to age and condition. As such, the pace of retirements will significantly increase over the next few years.

[1] Calculated by comparing the 2008 FRSR balance of $4,688,112 to the 2012 balance of $4.395,151
[2] Based on2009 through 2012 retirement transactions of $3.3 million compared to the 2008 plant in service balance of $115.7 million

Gannett Fleming has advised that the level of accumulated FRSR deficiency will continue to increase at an increasingly rapid pace in future years, if FRSR funding is not re-instated into the deprecation calculations. As noted above there are two independent forces that are causing increases in the amount of the deficiency, that will cause the deficiency to grow at an exponential rate, as witnessed over the past 3 year period. The inter-generational inequity of the current process as mandated by the Board in Decision 2009-02 has already caused future rate-payers to bear $7.9 million of additional burden, and continuation of this practice will see this burden increase by exponential amounts in future years.

The concept of inclusion of net salvage provisions into the depreciation rate calculations has been a topic of debate in many regulatory jurisdictions across Canada since the issuance of the YUB Board Decision 2009-02. As indicated in the Additional Evidence of Larry Edwin Kennedy filed with the current Yukon Electrical Application, this topic has received considerable attention in the depreciation rate filings in many jurisdictions. However, notwithstanding the significant amount of regulatory debate, the inclusion of net salvage percentages in the depreciation rate calculations continues to be widely accepted throughout Canada and North America. Furthermore, the topic of re-instatement of net salvage into depreciation rate calculations has been specifically discussed in hearings in British Columbia in 2011, in which the BCUC specifically allowed FortisBC Energy Inc. to re-instate collection of net salvage as part of their depreciation rate calculations. As stated by the BCUC in FortisBC Energy's 2012-2013 Revenue Requirements and Rates Decision, dated April 12, 2012, pages 83-84:

> The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.

While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.

For the above reasons, Yukon Electrical is of the view that the completion of an updated depreciation study was necessary and appropriate.

YUB-YECL-81

Reference: Depreciation, YECL Application, page 7-1

For this depreciation study, Yukon Electrical has incorporated the usage of a life span analysis (similar to hydro generation) for each of its diesel generation locations. This will allow for more accurate depreciation rates for diesel generation facilities.

Request:

(a) Please describe and explain the method used to determine the depreciation expense for diesel generation facilities in prior YECL applications.

(b) Please explain lifespan analysis.

Response:

(a) In prior depreciation studies, the diesel generation facilities were depreciated using group depreciation methods with the use of an average service life estimate combined with an estimated retirement pattern (Iowa curve shape) on an account by account basis. In this manner the assets within each account are depreciated based on the expected average service life based on physical factors such as wear and tear, exposure to the elements, technology, etc. As such, the depreciation rates did not specifically consider economic factors on the facility as a whole that are now considered as part of the life span analysis.

(b) Long life assets such as electric generation plants are restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also, and to a much greater extent, by economic forces of retirement such as changes in demand and capacity, environmental factors, and alternative sources of generation. Generally, environmental forces of retirement will be the dominate retirement force than physical forces of retirement. In Yukon Electrical's situation, it is expected that economic forces of retirement will be the dominant force of retirement. As such, Gannett Fleming recommends the use of Life Span in the development of depreciation rate for electric generation plant.

The concept referred to with the terms "Life span", "economic life" or "economic planning horizon" or "truncation date" (which have similar meaning within

depreciation literature) is the key parameter used to set appropriate depreciation rates that accurately reflect the annual consumption in service value when nonphysical forces of retirement are probable. Appropriate depreciation rates also help to ensure that both long term generational equity and a reasonable opportunity for the recovery of investment are achievable.

The use of Life span in the calculation of depreciation rates introduces the concept of Terminal or final retirements into the calculation to represent those retirements described by the truncation of the interim survivor curve at the truncation date. The following diagram provides an illustration of the concept of terminal retirement in the calculation of the estimated average service life. In this illustration a life span date of 2025 is used in combination with an R2-70 Iowa curve.


Illustrative Example of Use of a Life Span
Original and Smooth Survivor Curves
IOWA 70 -R3 (Interim Survivor Curve)
Conceptual Pattern of Terminal Retirements
Truncation at End of Year 2025
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120
Age in Years
Period of Interim or Ongoing Retirements
Period of Terminal or Final Retirements

YUB-YECL-82

Reference: Deferral on depreciation parameters, process to determine whether a change in depreciation parameters may be required, YECL Application, pages 7-2 and 7-3

Yukon Electrical is requesting approval for a deferral account to allow it the ability to file future applications, as necessary, to change its depreciation parameters within the 2013-2015 test period, and flow through the impact of any such change to customers within the test period.

If a significant change has occurred, but not only in the current year but over a few years (i.e.2 to 3) that cannot be discounted as being a non-typical transaction and appears to be a valid retirement pressure that is supported by the appropriate engineers and management, than a new depreciation parameter may be warranted.

Request:

(a) Please explain why the above-noted request may not be considered as retroactive ratemaking?

(b) Would the YECL request to potentially change depreciation parameters shift forecast risk for this item form YECL to customers?

(c) The timing required to detect a significant change extends beyond the requested test period. Would it be more efficient then to propose changes to depreciation parameters in a subsequent GRA?

(d) YECL has stated that, “each change in depreciation parameters must be assessed on an individual basis with regard to materiality”. Please provide YECL’s views of what those materiality guidelines should be.

Response:

(a) This deferral account should not be considered retroactive ratemaking as it is simply requesting the opportunity to reflect in rates the impact of updated depreciation parameters potentially more often than what would have been necessary prior to the advent of IFRS. In the past, depreciation studies were filed in regular intervals to update depreciation parameters. These updated

depreciation parameters were filed with regulators, tested, approved and ultimately reflected in both the GAAP and regulatory books of the utility. The only thing that has changed in today's IFRS environment is that IFRS requires depreciation parameters to be reviewed on an annual basis. This means there is now a risk that there will be different depreciation parameters for IFRS and utility purposes if there is not an opportunity to update utility depreciation parameters at the same time as they are changed for IFRS purposes.

(b) As detailed in Section 7 of its Application, the intention of Yukon Electrical's requested deferral is, to the extent possible, to permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, there is no shifting of forecast risk for this item from Yukon Electrical to customers.

Significant changes in the expected life of assets or gross salvage and costs of retirement of assets can be caused by various events, including a change in technology. Such an event or events could have an immediate impact on the expected life of assets or gross salvage and costs of retirement in the same year in which in which it occurs. Conversely, such event or events could have an impact on the expected life of assets or gross salvage and costs that is not immediate but is only revealed after several years of data and trend information is analyzed. Yukon Electrical would be required to update its depreciation parameters if either type of situation were to occur.

If a material change is warranted upon Yukon Electrical's annual review of depreciation parameters as described on pages 7-2 and 7-3 of the Application, Yukon Electrical would be obligated to adjust its depreciation parameters and the resulting depreciation rates and expense for that year for financial statement purposes in order to obtain a clean audit opinion under IFRS. While the update to the depreciation parameters for regulatory purposes could wait until Yukon Electrical's next GRA is filed, the delay would create a situation where there Yukon Electrical would be managing two separate sets of books for property plant and equipment.

Yukon Electrical would only update its depreciation parameters if the resulting impact on depreciation expense was large enough to require adjustment for financial statement purposes. Such a change would have to be greater than $100,000.

YUB-YECL-83

Reference: Depreciation, YECL Application, Schedules 7-1 to 7-5 inclusive

Request:

(a) Please restate the Section 7 schedules, using the methods and Iowa curves approved in YECL's 2008-09 GRA.

(b) In schedule 7.5, please fully explain the transition from ($382,000) to $71,000 (2012 Actual to 2013 Forecast) for the total amortization of differences.

Response:

(a) Please refer to YUB-YECL-83(a) Attachment 1.

(b) The amortization of differences is developed using the forecast life and net salvage parameters for each fixed asset account. Using the forecast life and net salvage parameters assumes that these parameters have been in existence since day 1 for each fixed asset account and determines a calculated accrued depreciation to the date of the depreciation study. This calculated accrued depreciation is then compared to the actual booked accumulated depreciation. If the booked value is greater than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account, as an annual provision for true-up, resulting in an annual depreciation expense decrease. Similarly, if the booked value is less than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account resulting in an annual depreciation expense increase. Thus, the difference between the previous depreciation study amount of ($382,000) to the current depreciation study amount of $71,000 reflects depreciation parameter forecast changes.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.1 - Depreciation Expense
Using 2008/2009 Depreciation Parameters

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1	General Provision	S. 7.2, 7.3,7.4 L.51	3,585	3,892	4,108	4,559	4,641	5,529	6,386	7,173	3,760	4,067
2	Amortization of Differences	S.7.5 L. 51	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)
3	Vehicle Depreciation Capitalized	S.8.6 L. 21	(22)	(64)	(43)	(48)	(67)	(75)	(82)	(87)	(24)	(24)
4	Total Depreciation Expense	S.1.1 L.12	3,181	3,446	3,683	4,129	4,192	5,072	5,922	6,704	3,354	3,661

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.2 - 2013 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2013 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2013 Total Depreciation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		263	3.33%	9	180	3	12
4	423 00	Hydro Resv, Dams & Waterways		2,375	3.57%	85	1,627	29	114
5	425 00	Hydro Generators		2,676	3.76%	101	1,833	34	135
6	426 00	Hydro Accessory Electrical Equip		158	3.24%	5	108	2	7
7	427 00	Hydro Misc Equip		69	3.70%	3	47	1	4
8		Total Production - Hydro		5,539		203	3,794	69	272
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,238	2.71%	61	491	7	68
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	2.97%	93	688	10	103
13	445 00	Generating Equipment & Prime Mover - Other		7,270	3.59%	261	1,594	29	290
14	446 00	Accessory Electric Equipment - Other		2,077	2.94%	61	455	7	68
15	447 00	Misc. Power Plant Equipment - Other		794	3.11%	25	174	3	28
16		Total Production - Diesel		15,517		501	3,402	56	557
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.49%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,331	1.51%	20	102	1	21
24	473 00	Poles, Towers & Fixtures		34,533	2.67%	922	2,559	34	956
25	474 00	Overhead Conductor		22,282	2.67%	595	1,703	23	618
26	474 10	Services - Overhead		2,979	2.59%	77	228	3	80
27	475 00	Underground Conductor		22,880	2.41%	551	1,732	21	572
28	475 10	Services - Underground		3,097	2.10%	65	237	2	67
29	476 10	Meters		1,984	4.10%	81	542	-	81
30	476 30	AMR - Meters		68	4.52%	3	-	-	3
31	477 10	Substation Equipment		3,131	2.77%	87	239	3	90
32	478 10	Street Lighting		9,600	3.98%	382	396	8	390
33	478 20	Sentinel Lights		285	2.99%	9	-	-	9
34	479 10	Line Transformers		28,058	3.03%	850	2,032	31	881
35		Total Distribution Plant		130,227		3,642	9,770	126	3,768
36									
37		General Plant							
38	482 00	Structures & Improvements		3,634	3.10%	113	1,124	17	130
39	483 00	Office Furniture & Equipment		194	5.70%	11	11	-	11
40	483 20	Computer Equipment		47	18.73%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		2,954	9.34%	276	432	20	296
42	485 00	Tool & Work Equipment		843	6.33%	53	86	3	56
43	486 00	Communication Structures & Equipment		938	5.50%	52	65	2	54
44	488 20	Company Housing		475	2.66%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,251	4.00%	-	650	26	26
47	493 00	Demand Side Management		-	10.00%	-	481	48	48
48	496 00	Software		2,204	10.00%	220	705	35	255
49		Total General Plant		12,541		747	3,555	151	898
50									
51		Plant Studied		165,208		5,127	20,522	402	5,529
52		Plant Not Studied - Land		380					
53		Total Plant	S.8.6 L.10	165,588					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.3 - 2014 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2014 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2014 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		442	3.54%	16	157	3	19
4	423 00	Hydro Resv, Dams & Waterways		4,001	3.68%	147	1,421	26	173
5	425 00	Hydro Generators		4,508	3.79%	171	1,601	30	201
6	426 00	Hydro Accessory Electrical Equip		266	3.49%	9	94	2	11
7	427 00	Hydro Misc Equip		116	4.06%	5	41	1	6
8		Total Production - Hydro		9,334		348	3,315	62	410
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,729	2.72%	74	649	9	83
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,826	2.97%	114	910	14	128
13	445 00	Generating Equipment & Prime Mover - Other		8,865	3.88%	344	2,109	41	385
14	446 00	Accessory Electric Equipment - Other		2,532	2.97%	75	602	9	84
15	447 00	Misc. Power Plant Equipment - Other		968	3.11%	30	230	4	34
16		Total Production - Diesel		18,919		637	4,501	77	714
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.48%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,432	1.50%	21	113	1	22
24	473 00	Poles, Towers & Fixtures		37,092	2.67%	990	2,844	38	1,028
25	474 00	Overhead Conductor		23,985	2.67%	640	1,887	25	665
26	474 10	Services - Overhead		3,206	2.59%	83	252	3	86
27	475 00	Underground Conductor		24,612	2.40%	591	1,921	23	614
28	475 10	Services - Underground		3,334	2.10%	70	262	3	73
29	476 10	Meters		2,525	4.11%	104	(377)	-	104
30	476 30	AMR - Meters		68	4.50%	3	1,580	36	39
31	477 10	Substation Equipment		3,370	2.79%	94	265	4	98
32	478 10	Street Lighting		9,996	3.96%	396	945	19	415
33	478 20	Sentinel Lights		285	2.93%	8	-	-	8
34	479 10	Line Transformers		30,090	3.03%	912	2,364	36	948
35		Total Distribution Plant		139,997		3,912	12,057	188	4,100
36									
37		General Plant							
38	482 00	Structures & Improvements		4,758	3.14%	149	315	5	154
39	483 00	Office Furniture & Equipment		205	6.67%	14	9	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		3,386	9.50%	322	868	41	363
42	485 00	Tool & Work Equipment		930	6.67%	62	137	5	67
43	486 00	Communication Structures & Equipment		1,003	6.67%	67	11	-	67
44	488 20	Company Housing		475	2.65%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		481	10.00%	48	522	26	74
48	496 00	Software		2,909	10.00%	291	7	-	291
49		Total General Plant		16,096		1,051	1,869	77	1,128
50									
51		Plant Studied		185,730		5,982	21,742	404	6,386
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	186,110					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.4 - 2015 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2015 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2015 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		600	3.61%	22	-	-	22
4	423 00	Hydro Resv, Dams & Waterways		5,422	3.71%	201	-	-	201
5	425 00	Hydro Generators		6,110	3.79%	232	-	-	232
6	426 00	Hydro Accessory Electrical Equip		360	3.57%	13	-	-	13
7	427 00	Hydro Misc Equip		157	4.10%	6	-	-	6
8		Total Production - Hydro		12,649		474	-	-	474
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		3,378	2.78%	94	798	11	105
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		4,736	2.99%	142	1,118	17	159
13	445 00	Generating Equipment & Prime Mover - Other		10,973	3.91%	429	2,592	51	480
14	446 00	Accessory Electric Equipment - Other		3,134	3.01%	94	740	11	105
15	447 00	Misc. Power Plant Equipment - Other		1,198	3.14%	38	283	4	42
16		Total Production - Diesel		23,420		797	5,531	94	891
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.47%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,545	1.50%	23	109	1	24
24	473 00	Poles, Towers & Fixtures		39,937	2.67%	1,066	2,736	37	1,103
25	474 00	Overhead Conductor		25,872	2.67%	691	1,825	24	715
26	474 10	Services - Overhead		3,459	2.60%	90	244	3	93
27	475 00	Underground Conductor		26,534	2.40%	637	1,855	22	659
28	475 10	Services - Underground		3,596	2.10%	76	254	3	79
29	476 10	Meters		2,148	4.10%	88	(377)	-	88
30	476 30	AMR - Meters		1,648	4.54%	75	2,283	52	127
31	477 10	Substation Equipment		3,636	2.80%	102	256	4	106
32	478 10	Street Lighting		10,941	3.97%	434	813	16	450
33	478 20	Sentinel Lights		285	2.87%	8	-	-	8
34	479 10	Line Transformers		32,454	3.03%	983	2,277	34	1,017
35		Total Distribution Plant		152,054		4,273	12,274	196	4,469
36									
37		General Plant							
38	482 00	Structures & Improvements		5,073	3.13%	159	305	5	164
39	483 00	Office Furniture & Equipment		214	6.67%	14	2	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		4,254	9.87%	420	730	36	456
42	485 00	Tool & Work Equipment		1,066	6.67%	71	84	3	74
43	486 00	Communication Structures & Equipment		1,014	6.67%	68	12	-	68
44	488 20	Company Housing		475	2.63%	12	-	-	12
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		1,003	10.00%	100	730	37	137
48	496 00	Software		2,916	10.00%	292	57	3	295
49		Total General Plant		17,965		1,221	1,920	84	1,305
50									
51		Plant Studied		207,472		6,799	19,725	374	7,173
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	207,852					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule of Amortization of Differences
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	YFR/ Curve	Life	Net Salvage	Depn. Rates	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1		Production - Hydro												
2														
3	422 00	Hydro Structures		R2	72	-10%	3.36%	(14)	(14)	(14)	(14)	(14)	(14)	(14)
4	423 00	Hydro Resv, Dams & Waterways		R3	103	-10%	3.36%	-	-	-	-	-	-	-
5	425 00	Hydro Generators		R3	85	-10%	3.36%	-	-	-	-	-	-	-
6	426 00	Hydro Accessory Electrical Equip		R3	45	-10%	3.36%	-	-	-	-	-	-	-
7	427 00	Hydro Misc Equip		R2	30	-10%	3.36%	-	-	-	-	-	-	-
8		Total Production - Hydro						(14)	(14)	(14)	(14)	(14)	(14)	(14)
9														
10		Production - Diesel												
11	442 00	Structures and Improvements - Other		R2.5	40	-10%	2.74%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		R4	35	-20%	3.00%	(8)	(8)	(8)	(8)	(8)	(8)	(8)
13	445 00	Generating Equipment & Prime Mover - Other		R2.5	26	-10%	3.69%	(40)	(40)	(40)	(40)	(40)	(40)	(40)
14	446 00	Accessory Electric Equipment - Other		R3	35	0%	3.00%	(15)	(15)	(15)	(15)	(15)	(15)	(15)
15	447 00	Misc. Power Plant Equipment - Other		R3	40	0%	3.15%	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16		Total Production - Diesel						(71)	(71)	(71)	(71)	(71)	(71)	(71)
17														
18		Transmission												
19	457 00	Substation Equipment		R4	50	-10%	2.55%	(3)	(3)	(3)	(3)	(3)	(3)	(3)
20		Total Transmission						(3)	(3)	(3)	(3)	(3)	(3)	(3)
21														
22		Distribution Plant												
23	471 00	Land Rights		R3	75	0%	1.52%	-	-	-	-	-	-	-
24	473 00	Poles, Towers & Fixtures		R3	45	-75%	2.67%	(75)	(75)	(75)	(75)	(75)	(75)	(75)
25	474 00	Overhead Conductor		R4	45	-80%	2.69%	(24)	(24)	(24)	(24)	(24)	(24)	(24)
26	474 10	Services - Overhead		R3	45	-10%	2.62%	(7)	(7)	(7)	(7)	(7)	(7)	(7)
27	475 00	Underground Conductor		R3	45	-50%	2.11%	(5)	(5)	(5)	(5)	(5)	(5)	(5)
28	475 10	Services - Underground		R4	40	-10%	2.63%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
29	476 10	Meters		L0	15	0%	4.06%	-	-	-	-	-	-	-
30	476 30	AMR - Meters		R2.5	15	0%	4.54%							
31	477 10	Substation Equipment		R4	40	-10%	2.92%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
32	478 10	Street Lighting		R3	30	-10%	4.13%	(61)	(61)	(61)	(61)	(61)	(61)	(61)
33	478 20	Sentinel Lights		R2	23	0%	3.37%	-	-	-	-	-	-	-
34	479 10	Line Transformers		R3	45	-10%	3.04%	(69)	(69)	(69)	(69)	(69)	(69)	(69)
35		Total Distribution Plant						(253)	(253)	(253)	(253)	(253)	(253)	(253)
36														
37		General Plant												
38	482 00	Structures & Improvements		L3	40	0%	3.19%	-	-	-	-	-	-	-
39	483 00	Office Furniture & Equipment		SQ	15	0%	4.49%	2	2	2	2	2	2	2
40	483.20	Computer Hardware/Software		SQ	5	0%	20.00%	-	-	-	-	-	-	-
41	484 00	Transportation & Mobile Equipment		L0	12	25%	10.82%	(51)	(51)	(51)	(51)	(51)	(51)	(51)
42	485 00	Tool & Work Equipment		SQ	15	0%	6.54%	(3)	(3)	(3)	(3)	(3)	(3)	(3)
43	486 00	Communication Structures & Equipment		SQ	15	0%	5.79%	11	11	11	11	11	11	11
44	488 20	Company Housing		R3	40	10%	2.47%							
45	491 00	Franchise & Consent					0.00%	-	-	-	-	-	-	-
46	492 00	Licence - Fish Lake					10.00%							
47	493 00	Demand Side Management												
48	496 00	Software		S3	10	0%	10.00%	-	-	-	-	-	-	-
49		Total General Plant						(41)	(41)	(41)	(41)	(41)	(41)	(41)
50														
51		Total Amortization of Differences	S. 7.1 L. 2					(382)	(382)	(382)	(382)	(382)	(382)	(382)

YUB-YECL-84

Reference: Average life curves, YECL Application, Section 7, Attachment 1, page 31 of 208

In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit … It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group, assuming no contrary relevant factors external to the analysis of historical data.

Request:

(a) What is used to determine which curve gives the best fit? Is a goodness-of-fit test or some other statistical method used to make the determination? Please explain.

(b) If statistics are not the only factor used in determining the best fitting curve, what weighting is given to statistical analysis versus "contrary relevant factors"?

Response:

(a) Gannett Fleming employed a visual fitting process, which includes the following steps:

1. The observed life table as determined in the Retirement rate analysis is plotted in accordance with the procedures as described at pages II-10 through II-23 of the Gannett Fleming report;

2. The areas of the observed life table that the analyst considered to represent data points that are representative of future retirement causes and expectations are determined for each account, giving consideration to:

   i. placing reduced emphasis on the tail portion of the observed life table (generally once plant exposed to retirement is less than 1% of total plant exposed to retirement at age 0);

   ii. placing reduced emphasis on the early portion of the life curve; and

iii. identification of any unusual data points in the observed life table at any age and determination of the reasons for retirement causing the unusual data point;

3. A statistically determined best fit is determined through the calculation of the sum of least squared differences procedure. In this procedure, the variance of each actual data point determined in the retirement rate analysis is compared to the corresponding data point of the smoothed Iowa curve through the calculation of a residual measure in which each variance is squared and the squared differences are summed. The square root of the sum of the squared differences is known as the residual measure of the fit of the smoothed curve to the observed life table; and

4. The statistical best fit (as determined above) for each family of curves is plotted against the observed life table. In addition, a number of smoothed Iowa curves are plotted against the observed life table through the period of most reliance to allow the depreciation analyst to visually inspect the smoothed Iowa curve against the plotted observed life table.

While this process begins with the determination of a best fit curve determined through the calculation of the residual measures, the statistical fitting process does not provide any weighting of the observed life table data points. Therefore, the statistical best fits are only used as a starting point for the remainder of the curve fitting process, in order that the analyst can place appropriate weighting on the various segments of the observed life table.

(b) Please refer to YUB-YECL-84(b) Attachment 1 which is a summary of the relative weighting assigned to each of the factors considered in the average service life analysis for each account.

THE YUKON ELECTRICAL COMPANY LIMITED

SUMMARY OF RELATIVE WEIGHTING APPLIED TO VARIOUS CONSIDERATION IN THE AVERAGE SERVICE LIFE ESTIMATATION

	DESCRIPTION	RECOMMENDED SURVIVOR CURVE	PREVIOUSLY RECOMMENDED CURVE	RETIREMENT RATE ANALYSIS	PEER ANALYSIS	MANAGEMENT AND OPERATING INTERVIEWS	GANNETT FLEMING EXPERIENCE	COMMENTS
	(1)	(2)	(4)	(5)	(6)=(5)/(3)			
GENERATION								
HYDRO GENERATION (LIFE SPAN OF 2052)								
422.00	HYDRO STRUCTURES	72-R2	none	none	high	medium	medium	
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103-R3	none	none	high	medium	medium	Due to lack of specific retirement information the average service lives as recently approved for YEC were adopted as the recommended life to YECL in this study for all Hydro Generation accounts
425.00	HYDRO GENERATORS	85-R3	none	none	high	medium	medium	
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45-R3	none	none	high	medium	medium	
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30-R2	none	none	high	medium	medium	
DIESEL GENERATION								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	medium	medium	low	high	medium	Little actual retirement experience
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	high	high	low	high	medium	
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	high	high	low	high	medium	
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	high	high	low	high	medium	
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	high	low	low	high	medium	Little actual retirement experience
SUBSTATION PLANT								
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50-R4	medium	medium	medium	medium	medium	
DISTRIBUTION PLANT								
471.00	LAND RIGHTS	75-R3	high	none	high	medium	medium	Account has no actual retirement experience
473.00	POLES, TOWERS AND FIXTURES	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
474.00	OVERHEAD CONDUCTOR	45-R4	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
474.10	OVERHEAD SERVICES	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
475.00	UNDERGROUND CONDUIT	45-R3	medium	low	medium	medium	medium	Little actual retirement experience
475.10	UNDERGROUND SERVICES	40-R4	medium	medium	medium	medium	medium	Little actual retirement experience
476.10	METERS	15-L0	low	medium	medium	high	high	
476.30	AMR - METERS	15-R2.5	none	low	high	high	high	
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	medium	low	medium	high	medium	Little actual retirement experience
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	medium	medium	medium	medium	low	
478.20	SENTINEL LIGHTS	23-R2	medium	medium	medium	medium	low	
479.10	LINE TRANSFORMERS	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	high	medium	medium	high	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	medium	none	medium	high	high	
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	high	none	high	high	medium	
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	medium	high	medium	high	low	
485.00	TOOLS AND INSTRUMENTS	15-SQ	high	none	medium	high	medium	
486.00	COMMUNICATION EQUIPMENT	15-SQ	high	none	medium	high	medium	
488.20	HOUSES	40-R3	high	none	low	medium	medium	Account has no actual retirement experience

YUB-YECL-85

Reference: Survivor curve judgments, YECL Application, Section 7, Attachment 1, page 31 of 208

The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and engineering staff, and survivor curve estimates form previous studies of this Company and other electric distribution companies.

Request:

Please explain why any weighting should be given to other distribution companies.

Response:

In the development of average service life estimates, consideration should be given to all forces of retirement that can be reasonably expected to occur. In order to forecast the forces of retirement, a number of estimation "tools" are available, including the review of historic retirement experience, discussions with operations and management representatives, industry experience, upcoming capital programs and experience gained from the review of relevant peer companies. In this manner, the depreciation analyst can form an average service life or net salvage estimate based on a wide variety of input. The weighting provided to each of these inputs is provided in response to information request YUB-YECL-84(b) Attachment 1.

With specific reference to the use of peer information, it should be noted that it provided additional weighting in circumstances where the company has a limited amount of actual retirement experience, and where peer companies have experienced relevant retirement activity. Additionally, Gannett Fleming uses the peer analysis as a benchmark for the determination of the reasonableness of the average service life and net salvage analysis developed from the use of other analysis tools. In this manner, the use of peers is not the primary estimation method, but rather a check of reasonableness. In circumstances where average life or net salvage parameters determined with company specific information are out of the range of the peer analysis, further interview and discussions are held with company representatives to determine the potential reasons that the company retirement history would differ from that of the peers.

YUB-YECL-86

Reference: Asset accounts, YECL Application, Section 7, Attachment 1, pages 31 of 208 to 35 of 208

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 1983 through 2011, and in part through a comparison to peer electric distribution companies.

The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation.

Request:

(a) For each of the asset accounts listed, please provide a table that shows the Iowa curve previously used and approved by the Board, the Iowa curve recommended in this application, the corresponding depreciation rates previously approved and now recommended, and if there is a change an explanation of the primary factor for that change from what was approved to what is being recommended.

(b) In general, does a change in the Iowa curve from a 50-RX to a 45-RX imply a change in expected service life form 50 years to 45 years?

(c) For Account 475.00 the change from Iowa 50-R4 to Iowa 45-R3 is "to better fit industry retirement trends". What curve best represents YECL's retirement trends for that asset class?

(d) For account 478.10, the Iowa curve has been changed from an Iowa 25-R3 to an Iowa 30-R3 "to better fit industry retirement trends". Please define the industry, the trend, and the location of that industry and how those locations are an appropriate match for a location such as Yukon.

(e) Please explain why the retirement history for Accounts 422.00 through 427.00 were not available. What was used in past studies for YECL?

Response:

(a) Please refer to YUB-YECL-86(a) Attachment 1, which identifies the primary factor for the material change from what was approved in the last depreciation study to what is being recommended for the Iowa curve and depreciation rates in this application.

(b) Confirmed, given the context of the example where the survivor curve shape (i.e. RX) remains constant and the average service life differs.

(c) The curve that best represents Yukon Electrical's retirement trends for the asset class of 475.00 is within the range of the electric distribution systems peer analysis (YUB-YECL-87(a)). The recommended Iowa curve appears to be trending towards a shorter survivor curve shape amongst Yukon Electrical's peers and within the range of Yukon Energy Corporation's approved Iowa curve.

(d) Please refer to the response to information request YUB-YECL-87. The analysis focused on a number of northern Canadian regulated distribution systems including Yukon Energy Corporation.

(e) Given the amount of investment in the hydro generation accounts, and further given the very limited amount of retirement history, in prior studies it was determined that the accounts could be analyzed and depreciated as one group. However, during the early stages of this current study, it was identified that some of the operating components will have an identifiably differing life expectation and replacement of some of the components is now likely in the near term. Therefore, during the preparation of this study, it was determined that the expected consumption of service value for this group of investment is better estimated through the analysis of the accounts individually.

The Yukon Electrical Company Limited
Comparison of Approved Iowa Curves and Depreciation Rates to Proposed Iowa Curves and Depreciation Rates

Acct.	Description	GRA Approved Iowa Curve	Recommended Iowa Curve	GRA Approved Depreciation Rate	Recommended Depreciation Rate	Explanation
	Production - Diesel					
442 00	Structures and Improvements - Other	40-R2.5	40-R2.5	3.07%	3.13%	Age Surviving Balance
444 00	Fuel Holders, Producers, & Acc. Equipment - Other	35-R4	35-R4	3.69%	3.80%	Age Surviving Balance
445 00	Generating Equipment & Prime Mover - Other	27-R2.5	26-S2.5	4.24%	4.34%	Change in Average Service Life Estimate
446 00	Accessory Electric Equipment - Other	35-R3	35-R3	3.32%	3.52%	Age Surviving Balance
447 00	Misc. Power Plant Equipment - Other	35-R3	40-R3	2.92%	2.96%	Change in Average Service Life Estimate
	Transmission					
457 00	Substation Equipment	40-R4	50-R4	2.25%	2.25%	-
	Distribution Plant					
471 00	Land Rights	75-R3	75-R3	1.51%	1.50%	-
473 00	Poles, Towers & Fixtures	40-R3	45-R3	4.20%	4.20%	-
474 00	Overhead Conductor	40-R3	45-R4	4.16%	4.16%	-
474 10	Services - Overhead	40-R3	45-R3	2.57%	2.58%	-
475 00	Underground Conductor	50-R4	45-R3	3.61%	3.61%	-
475 10	Services - Underground	40-R4	40-R4	2.87%	2.86%	-
476 10	Meters	n/a	15-L0	7.65%	8.09%	Change in Average Service Life Estimate
476 30	AMR - Meters	25-S2	15-R2.5	7.31%	7.13%	Change in Average Service Life Estimate
477 10	Substation Equipment	35-R3	40-R4	2.75%	2.75%	-
478 10	Street Lighting	25-R3	30-R3	3.77%	3.75%	Change in Average Service Life Estimate
478 20	Sentinel Lights	23-R2	23-R2	2.99%	2.93%	-
479 10	Line Transformers	35-R3	45-R3	2.66%	2.65%	-
	General Plant					
482 00	Structures & Improvements	32-R4	40-L3	2.63%	2.67%	Age Surviving Balance
483 00	Office Furniture & Equipment	15-SQ	15-SQ	5.70%	6.67%	Completion of true-up correction
483 20	Computer Equipment	5-SQ	5-SQ	18.73%	20.00%	Completion of true-up correction
484 00	Transportation & Mobile Equipment	10-R0.5	12-L0	6.44%	6.59%	Age Surviving Balance
485 00	Tool & Work Equipment	15-SQ	15-SQ	6.33%	6.67%	Completion of true-up correction
486 00	Communication Structures & Equipment	15-SQ	15-SQ	5.50%	6.67%	Completion of true-up correction
488 20	Company Housing	40-R3	40-R3	2.93%	2.91%	-

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Reference: Estimation of net salvage, YECL Application, Section 7, Attachment 1, pages 35 to 37 of 208

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 1983 through 2011, and in part through a comparison to peer electric distribution companies.

The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation.

Request:

(a) Please list the peer distribution companies and the weighting given to each company.

(b) Please confirm whether the "Traditional Approach" conforms with past directions form this Board.

(c) Please provide a table showing for each asset account, the approved net salvage percentages approved in the 2008-09 YECL GRA and the net salvage percentages recommended in the current application.

Response:

(a) Please refer to YUB-YECL-87(a) Attachment 1 for a list of peer distribution companies. Gannett Fleming does not assign any specific weighting to each company in the peer analysis. The peer analysis tool is a guide in formulating the reasonableness of a range in order to test whether the preliminary recommendation falls within the range of currently approved parameters.

(b) Confirmed. In previous applications, the request for net salvage has been prepared using the "traditional approach".

(c) Please refer to YUB-YECL-87(c) Attachment 1 for a table of the net salvage percentages approved in the 2008-09 Yukon Electrical GRA along with the net salvage percentages recommended of this current application.

YUKON ELECTRICAL COMPANY LIMITED - RECOMMENDED CURVES AND PEER ANALYSIS

YUKON ELECTRICAL COMPANY LIMITED - Peer Life Analysis

Account		Current Curves 2008	NB Power Corporation 0	ATCO Electric 2010	Yukon Energy Corporation 2012	Manitoba Hydro 2012	Fortis Alberta 2011	Fortis BC 2011	Northland Utilities Yellowknife 2004	Northland Utilities 2011	Best Fit	Recom-mended Curves
	HYDRAULIC PRODUCTION ASSETS											
42000	Hydraulic Production	30-R3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		40-R4
	DIESEL PRODUCTION ASSETS											
44200	Structures and Improvements	40-R2.5	n/a	n/a	72-R2	n/a	n/a	n/a	n/a	n/a		40-R2.5
44400	Fuel holders, Products and Acc.	35-R4	n/a	n/a	25-R2	n/a	n/a	n/a	n/a	n/a		35-R4
44500	Generating Equipment and Prime Movers	27-R2.5	n/a	n/a	40-R2	n/a	n/a	n/a	n/a	n/a		26-S2.5
44600	Accessory Electric Equipment	35-R3	n/a	n/a	45-R3	n/a	n/a	n/a	n/a	n/a		35-R3
44700	Miscellaneous power Plant Equipment	35-R3	n/a	n/a	30-R2	n/a	n/a	n/a	n/a	n/a		40-R3
	TRANSMISSION ASSETS											
45700	Substation Equipment	40-R4	27-R2/35-R2	53-R3	54-S0	35-R2/45-R2	n/a	50-S4	31.R3	45-R4		50-R4
	DISTRIBUTION ASSETS											
47100	Land Rights	75-R3	30-SQ	75-R3	n/a	75-R3	36-L3	75-R3	75-R3	75-R3		75-R3
47300	Poles and Fixtures	40-R3	33-R1/34-R1.5	45-R2.5	35-R2	55-R3	45-R1.5	50-R3	45-R4	44-R4		45-R3
47400	Overhead Conductors	40-R3	40-R3/40-R1	55-R2.5	35-R2	60-R2	45-R1.5	45-R3	40-R4	50-R3		45-R4
47410	Overhead Services	40-R3	40-R3/40-R1	50-R4	40-R2	60-R2	n/a	45-R3	40-R3	50-R3		45-R3
47500	Underground Conduit	50-R4	35-L1	55-R4	40-R2.5	75-R4	58-R2	n/a	50-R3	59-R3		45-R3
47510	Underground Services	40-R4	35-R3/35-R4	50-R3	40-R2.5	45-R4/60-R4	n/a	n/a	40-R3	35-R3		40-R4
47610	Meters	n/a	22-R2	20-R1.5	30-R2	20-R1.5/25-R3	n/a	20-R1	20-L0.5	16-L0		15-L0
47630	AMR Meters	25-S2	27-R1.5	15-R2.5	n/a	20-R1.5/25-R3	15-R0.5	n/a	n/a	n/a	14-O4	15-R2.5
47710	Substation Equipment	35-R3	27-R2/35-R2	50-R3	40-R2	35-R2/45-R2	n/a	55-S3	31-R3	50-R2		40-R4
47810	Streetlighting & Signal Sytems	25-R3	33-R0.5	43-R4	40-R2	35-R3	20-R1	40-R4	35-S2.5	35-S3	59-R3	30-R3
47820	Sentinel Lights	23-R2	20-L0	31-R1	30-L2	n/a	n/a	n/a	n/a	30-S1.5		23-R2
47910	Lines Transformers	35-R3	25-R1/30-R3	40-R2.5	40-R2.5	50-R2	n/a	45-R4	35-S2.5	33-R3		45-R3
	GENERAL PLANT ASSETS											
48200	Structures and Improvements	32-R4	15-SQ/75-R2	55-R3	40-R2.5	65-R4	10-SQ	40-R3/35-R3	38-S2	45-R3	40-S2	40-L3
48300	Office Furniture and Equipment	15-SQ	15-SQ	15-R3	20-SQ	20-SQ	15-SQ	15-SQ	15-S4	15-SQ	14-S2.5	15-SQ
48320	Computers	5-SQ	6-SQ	5-S0.5	5-SQ	5-SQ/10-SQ	5-R4/7-SQ	10-SQ/5-SQ	5-R4	5-SQ	4-L1	5-SQ
48400	Vehicles and Mobile Heavy Equipment	10-R0.5	6-S3/17-L1.5	10-L1.5/25-R3	7-L2/25-R1.5	9-L2/35-R3	5-L1/3-SQ/14-S4	8-L3/20-L3	7-L2/26-R3	20-L1		12-L0
48500	Tools and Instruments	15-SQ	15-SQ	10-R2	20-SQ	15-SQ	10-SQ	15-SQ	10-S3	10-SQ	11-L3	15-SQ
48600	Communication and Structures	15-SQ	12-L4	25-R2	20-L4	n/a	n/a	15-SQ	15-R4	20-L3		15-SQ
48820	Houses	40-R3	n/a	12-L0	30-R3	n/a	n/a	n/a	n/a	n/a		40-R3

Notes:

1. NB Power refers to this account as Dusk to Dawn
2. A life span expiring at June 30, 2020.

YUKON ELECTRICAL COMPANY LIMITED - RECOMMENDED NET SALVAGE PERCENTAGE

YUKON ELECTRICAL COMPANY LIMITED - Peer Net Salvage Percentage Analysis

Account		Recom-mended Net Salv % 08/09 GRA	Approved Net Salv % 08/09 GRA	NB Power Corporation 2006	ATCO Electric 2010	Yukon Energy Corporation 2012	Manitoba Hydro 2012	Fortis Alberta 2011	Fortis BC 2011	Northland Utilities Yellowknife 2004	Northland Utilities 2011	Best Fit %'age	Recom-mended %'age	Comments
	HYDRAULIC PRODUCTION ASSETS													
42000	Hydraulic Production	-10	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		-10	
	DIESEL PRODUCTION ASSETS													
44200	Structures and Improvements	0	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-10	revised Jan 18 2013 as per site visit
44400	Fuel holders, Products and Acc.	-30	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-20	revised Jan 18 2013 as per site visit
44500	Generating Equipment and Prime Movers	-10	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-10	
44600	Accessory Electric Equipment	0	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		0	
44700	Miscellaneous power Plant Equipment	-5	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		0	
	TRANSMISSION ASSETS													
45700	Substation Equipment	0	0	0	-10	0	0	n/a	0	-11.9	-10		-10	revised Jan 18 2013 as per site visit
	DISTRIBUTION ASSETS													
47100	Land Rights	0	0	0	0	n/a	0	0	0	0	0		0	
47300	Poles and Fixtures	-60	0	0	-50	0	0	0	0	-35	-50		-75	
47400	Overhead Conductors	-70	0	0	-65	0	0	0	0	-30	-55		-80	
47410	Overhead Services	0	0	0	0	0	0	n/a	0	-10	-10		-10	revised Jan 18 2013 as per site visit
47500	Underground Conduit	-5	0	0	-10	0	0	0	n/a	0	-5		-50	
47510	Underground Services	0	0	0	0	0	0	n/a	n/a	0	-5		-10	revised Jan 18 2013 as per site visit
47610	Meters	0	0	0	0	0	0	n/a	0	1	0		0	
47630	AMR Meters	0	0	0	0	n/a	0	0	0	n/a	n/a		0	
47710	Substation Equipment	0	0	0	-5	0	0	n/a	0	-10	-5		-10	
47810	Streetlighting & Signal Sytems	-10	0	0	-10	0	0	-15	0	-5	0		-10	
47820	Sentinel Lights	10	0	0	20	0	n/a	n/a	0	n/a	20		0	
47910	Lines Transformers	-5	0	0	5	0	0	n/a	0	-30	-5		-10	
	GENERAL PLANT ASSETS													
48200	Structures and Improvements	5	5	0	-5	0	0	5/10	0	5	0		0	
48300	Office Furniture and Equipment	0	0	0	0	0	0	0	0	0	0		0	
48320	Computers	0	0	0	0	0	0	0	0	0	0		0	
48400	Vehicles and Mobile Heavy Equipment	20	20	0	10/20	0	0	15	20	25/15	20		25	
48500	Tools and Instruments	0	0	0	0	0	0	0	0	0	0		0	
48600	Communication and Structures	0	0	0	0	0	0	n/a	0	2	0		0	
48820	Houses	10	10	n/a	85	n/a	n/a	n/a	n/a	n/a	n/a		-10	

YUB-YECL-88

Reference: Results of study, YECL Application, Section 7, Attachment 1, page 43 of 208

An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service.

The service life and net salvage estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities.

Request:

(a) For the first quote above, please define "a long period of time". Would consistent accrual rates imply accuracy and a reasonable estimation of average service life for an asset?

(b) Why would any consideration be given to estimates made for other electric utilities?

Response:

(a) Normally depreciation studies are completed every 3 to 5 years for utilities of the size of Yukon Electrical. Gannett Fleming would view that a "long period of time" would be a period of longer than 5 years. Additionally, Gannett Fleming notes that consistent accrual rates that remain unchanged for periods of longer than 5 years do not necessarily imply accuracy and a reasonable estimation of average service life for an asset. In circumstances where accrual rates remain unchanged for long periods of time without any type of review or study, the accrual rate should not be considered as correct. However, accrual rates that remain consistent after having been studied likely represent a reasonable estimation of average service life.

(b) Please refer to the response to information request YUB-YECL-85.

YUB-YECL-89

Reference: Additional evidence, YECL Application, Section 7, Attachment 2

Request:

Was this additional evidence provided at the request of YECL? Please explain.

Response:

During the initial phases of the depreciation study, Yukon Electrical asked Gannett Fleming to provide an indication of whether any events have transpired since the Board's Decision regarding the inclusion of net salvage percentages that may support the reinstatement of net salvage percentages in the current study. In response to this request, Gannett Fleming embarked upon a process to research this issue among Canadian regulatory jurisdictions. Based on this research, it was Gannett Fleming's view that a number of significant events had transpired that support the inclusion of net salvage. Accordingly, Yukon Electrical requested that the Additional Evidence addressing this issue be prepared.

YUB-YECL-90

Reference: Inclusion of net salvage in the depreciation rate calculations, YECL Application, Section 7, Attachment 2

Request:

(a) To clarify, when net salvage is included in depreciation rates, are customers therefore currently paying for a service (salvage) or part thereof, which would occur in the future, and whose final cost is an estimate subject to change?

(b) Do accounting guidelines, MFRs or other rules or regulations delineate the use of depreciation parameters and FRSR policies based on type of ownership (Crown versus private)

(c) If FRSR balances are a current recovery for a future service (salvage), should such balances or contributions earn a return until said services are performed?

(d) If FRSR contributions are based on estimates, who is at risk for any variances between actual and forecast results? Please explain.

Response:

(a) Net salvage is an estimate of the future gross salvage received for property retired minus the future cost of retirement for plant retired, demolished, or removed. Negative net salvage is an estimated cost that will be incurred in the future on facilities that are being used to provide utility service to customers today, and as such, it helps to maintain generational equity, by ensuring that customers are paying for the full cost of receiving service at the time it is being provided. To not do so would result in inter-generational inequity in that future customers would pay for costs associated with facilities that were used to provide service to past customers.

(b) No.

(c) No. Yukon Electrical does not earn a return on FRSR balances prior to said services being performed. As detailed in Schedules 8.5 and 8.6 of its Application, a reinstatement of net negative salvage for Yukon Electrical results

in an increase to the forecast depreciation expense, an increase to the forecast accumulated depreciation and a reduction to the overall forecast rate base. As such, the inclusion of net negative salvage results in a lower rate base as compared to if net negative salvage was not included in Yukon Electrical's revenue requirement.

Please refer to YUB-YECL-90(c) Attachment 1 for Yukon Electrical's forecast rate base and return on rate base for 2013-2015 both including and excluding net negative salvage, which illustrates that the inclusion of net negative salvage results in a lower rate base.

(d) Net salvage parameters are reviewed at each GRA for applicability and accuracy to the future gross salvage and cost of retirement costs. These forecasts are vetted, tested and approved at each GRA. As such, these forecasts are based on the best information available to Yukon Electrical at the time and ensures that customers pay only the cost associated with assets required to provide utility service; no less and no more.

The Yukon Electrical Company Limited
Comparison of Rate Base and Return Including and Excuding Net Salvage

	As Filed Using 2013/2015 Proposed Depreciation Parameters - With Net Salvage	Using 2013/2015 Proposed Depreciation Parameters - No Net Salvage
2013		
Rate Base	72,329	73,312
Return on Rate Base	5,308	5,382
2014		
Rate Base	86,063	89,075
Return on Rate Base	6,255	6,473
2015		
Rate Base	96,812	102,028
Return on Rate Base	7,003	7,378